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Performance Profiles of Major Energy Producers 1997

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Data File Information

Historical Financial Reporting System (FRS) data are available from the Energy Information Administration's File Transfer Protocol (FTP) site and are also available on a 3.5-inch high-density diskette. These data cover the years 1977 through 1997, published in the Energy Information Administration's annual editions of *Performance Profiles of Major Energy Producers.* There are two different sets of data: aggregate data from the FRS survey form and multi-year tables from Appendix B of *Performance Profiles of Major Energy Producers.*

The Financial Reporting System 1977-1997 data files can be downloaded from the Energy Information Administration's FTP site (ftp://ftp.eia.doe.gov/pub/energy.overview/frs/), or by accessing the Energy Information Administration's Worldwide Web site (http://www.eia.doe.gov/emeu/finance/page2.html). For further assistance, please contact the National Energy Information Center at (202) 586-8800, FAX (202) 586-0727, TTY (202) 586-1181, or on INTERNET infoctr@eia.doe.gov.

To receive the Financial Reporting System 1977-1997 diskette, please contact Gregory P. Filas at telephone (202) 586-1347, Fax (202) 586-9753, or on INTERNET greg.filas@eia.doe.gov.

Preface

The information and analyses in *Performance Profiles of Major Energy Producers* is intended to provide a critical review, and promote an understanding, of the possible motivations and apparent consequences of investment decisions made by some of the largest corporations in the energy industry. (For a list of the companies covered in this report, the Financial Reporting System (FRS) companies, see Chapter 1, the box entitled "The FRS Companies in 1997.")

The economic performance of these companies, in financial and physical dimensions, continues to serve as a significant factor in evaluating past decisions (from a corporate and a governmental point of view) and guiding future options in the development and supply of energy resources in the U. S. and abroad. Also, this edition of *Performance Profiles of Major Energy Producers* initiates an increased scope of analysis that includes U.S.-based oil and gas producers and petroleum refiners outside the FRS respondent group.

Performance Profiles presents a comprehensive annual financial review and analysis of the domestic and worldwide activities and operations of the major U.S.-based energy-producing companies. Emerging issues in financial performance are also analyzed. The report primarily examines these companies' (the majors) operations on a consolidated corporate level, by individual lines-of-business, by major functions within each line-of-business, and by various geographic regions. A companion analysis of foreign investment[i] (trends and transactions) in U.S. energy resources, assets, and companies is also included as a separate chapter in the report. The coverage of foreign direct investment developments discussed in this chapter lags the discussion of the FRS companies by one year. This is due to the later release date of much of the foreign direct investment data.

Performance Profiles annually looks at aggregate changes in the U.S. energy industry resulting from major energy company current operations, and from strategic corporate decisions relating to profits, investments, and new business initiatives. Significant organizational decisions of the majors (such as those involving corporate mergers or joint ventures) are highlighted, and new strategic directions (such as concentration on core businesses or competencies, movements into new lines of business, or changes in global investment patterns) are discussed. Changes in the majors' investment and resource development patterns resulting in new or increased opportunities for independent oil and gas producers and independent petroleum refiners in the United States are also explored.

This edition of *Performance Profiles* reviews financial and operating data for the calendar year 1997. Although the focus is on 1997 activities and results, important trends prior to that time and emerging issues relevant to U.S. energy company operations are also discussed.

The analysis in this report is based on detailed financial and operating data and information submitted each year to the Energy Information Administration (EIA) on Form EIA-28, the Financial Reporting System (FRS). The analysis and FRS data are also supplemented by additional information from company annual reports and press releases, disclosures to the U.S. Securities and Exchange Commission, news reports and articles, and various complementary energy industry data sets.

Since the Form EIA-28 data are collected by the EIA on a uniform, segmented basis, the comparability of information across energy lines of business in unique to the FRS reporting system. For example, petroleum activities of the major U.S. energy companies (and financial returns attributable to these activities) can be compared to activities in other lines of energy business (such as coal, pipelines, power generation, and/or alternative energy) or nonenergy areas (such as chemicals). Similarly, financial returns and operating results from domestic activities can be compared to results from foreign activities and operations.

The information in Performance Profiles responds to the requirements of the Financial Reporting System, set forth in the Department of Energy Organization Act of 1977 (see http://www.eia.doe.gov/emeu/finance/page1a.html). Both this report, and similar energy financial analyses provided by the EIA (see http://www.eia.doe.gov/emeu/finance/page1a.html), are intended for use by the U.S. Congress, government agencies, industry analysts, and the general public.

See http://www.eia.doe.gov/emeu/finance/page1a.html for additional information about the Form EIA-28. Also see Appendix A of this report for information concerning the format of Form EIA-28, important financial reporting concepts and accounting principles, and other information about the Financial Reporting System. For a glossary of terms and definitions used in this report, see http://www.eia.doe.gov/emeu/perfpro/gloss97.html.

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[i]The purpose of the foreign direct investment report is to provide an assessment of the degree of foreign ownership of energy assets in the United States. Section 657, Subpart 8 of the U.S. Department of Energy Organization Act (Public Law 95-91) requires an annual report to Congress which presents: "…a summary of activities in the United States by companies which are foreign owned or controlled and which own or control United States energy sources and supplies…."

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Executive Summary

The energy industry generally and petroleum and natural gas operations in particular are frequently reacting to a variety of unsettling forces. Falling oil prices, economic upswings, currency devaluations, increasingly rigorous environmental quality standards, deregulation of electricity markets, and continued advances in exploration and production technology were among the challenges and opportunities to the industry in 1997. To analyze the extent to which these and other developments have affected energy industry financial and operating performance, strategies, and industry structure, the Energy Information Administration (EIA) maintains the Financial Reporting System (FRS).

Through Form EIA-28, major U.S. energy companies annually report to the FRS (see the box entitled "The FRS Companies in 1997" in Chapter 1 of this report). Financial and operating information is reported by major lines of business, including oil and gas production ("upstream"), petroleum refining and marketing ("downstream"), other energy operations, and nonenergy business.

A number of surprising contrasts were evident in the 1997 FRS data:

- Although world crude oil prices were down by about $2 per barrel from 1996 prices, the FRS companies' total profits were at a record high in 1997.

- The profitability of U.S. refining and marketing operations in 1997 was at the highest level in the 1990's, yet the FRS companies' asset commitment to these operations shrank noticeably. At the same time, other U.S. refiners grew.

- Two areas that have been in the least favor as upstream targets of investment in the 1990's, Canada and U.S. onshore locales, were prominent in the growth of oil and gas exploration and development expenditures in 1997.

- From the mid-1980's through 1997, capital and exploration expenditures of the FRS companies totaled $665 billion, but the FRS companies have only recently exhibited overall growth in their asset base.

- In the 1990's, and especially in 1997, energy sources outside the FRS companies' core competencies of petroleum and natural gas production and processing exhibited the steepest growth in assets. This heightened commitment was a reversal of the trend of the 1980's when this area was nearly abandoned.

- A reversal in the long downward trend in finding costs (the cost of adding oil and gas reserves) was evident in 1996 and 1997, even as advances in exploration and development technology continued to be implemented.

Performance Profiles of Major Producers 1997 examines the interplays of energy markets, companies' strategies, and government policies (in 1997 and in historical context) that gave rise to the above results. The report also analyzes other key aspects of energy company financial performance as seen through the multifaceted lens provided by the FRS data and complementary data for industry overall.

Highlights of this report include:

Corporate Profits and Cash Flow at Record Highs

Overall net income of the FRS companies was $32.1 billion in 1997, barely surpassing the previous record of $32.0 billion in 1996. Cash flow from operations in 1997 was $67.1 billion, also a record. Higher income and cash flow were attained despite a $2-per- barrel drop in the price of oil (based on the annual refiner acquisition cost of imported crude oil) between 1996 and 1997, a 10-percent decline. Generally, net income of the FRS companies declines when oil prices drop by 10 percent or more.

Offsets to lower oil prices in 1997 included higher natural gas prices and production, increased oil production outside the United States, and generally strong demand for petroleum products, particularly transport fuels (motor gasoline, diesel, and jet fuel).

The FRS companies' petroleum refining and marketing operations benefited from these developments, while income from worldwide oil and gas production changed little between 1996 and 1997. Lower crude oil prices led to reduced input prices for refiners. Refined product prices were also lower but did not slide as much as crude oil prices due to generally strong product demand. Currency devaluations by some Asian nations and their aftermath in the second half of the year were not nearly enough to offset the favorable market developments. As a result, refining margins improved and together with cuts in operating costs yielded the highest level of income from both domestic and foreign refining and marketing in the 1990's. Worldwide refining and marketing operations accounted for nearly 75 percent of the growth in the FRS companies' overall net income between 1996 and 1997 (after adjustments for unusual items such as litigation settlements).

Businesses outside petroleum also contributed to bottom-line results, in part reflecting generally strong economic growth in 1997. The FRS companies continued to reduce their interest expense by reducing the level of debt in their balance sheets.

Capital Expenditures Hit a Post-1986 Peak

Capital expenditures of the FRS companies totaled $61.9 billion in 1997, the highest level since 1984. The surge in capital expenditures reflected a strong upswing in interest by the majors in U.S. oil and gas production. About half of the $12-billion increase in the FRS companies' capital expenditures between 1996 and 1997 was attributable to heightened spending for U.S. upstream targets of investment. Part of the upswing was due to mergers and acquisitions, the largest of which were Burlington Resources' acquisition of Louisiana Land and Exploration for $3.0 billion and Texaco's acquisition of California oil producer Monterrey Resources for $1.4 billion. Apart from the effects of mergers and acquisitions, increased onshore spending was mainly for natural gas development, but companies with involvement in horizontal drilling or heavy oil production also tended to register increased expenditures.

Offshore locales continued to attract added investment from most of the FRS companies in 1997. The opportunity to apply advancing technologies, such as three-dimensional seismic imaging and sea-bottom robotics, to the search for large oil and gas fields in the Gulf of Mexico was a key factor in attracting the majors' interest. Engineering advances in offshore platform design and construction and in drilling techniques have made drilling and production from deepwater oil and gas deposits in the Gulf of Mexico economic. The FRS companies' exploration and development expenditures for offshore projects totaled $8.8 billion in 1997, up $2.1 billion from 1996 expenditures and triple the level of expenditures in 1992.

Outside the United States, capital expenditures for foreign oil and gas production reached an all-time record $16.9 billion in 1997, up 15 percent from 1996 expenditures. Foreign expenditures were geographically widespread; regionally, Canadian prospects were second only to the North Sea in leading the upswing in foreign expenditures. This was a surprising development since Canada had frequently been a target of investment cutbacks by the FRS companies in the 1990's. The renewed interest in Canada was a confluence of natural gas development in the established fields of Alberta (with the United States targeted for export sales), frontier developments off the coast of Newfoundland and Nova Scotia, and applications of advancing technologies including heavy oil extraction and horizontal drilling.

Capital expenditures for other energy, though small in relation to total investment, registered the steepest rise in 1997 among the FRS lines of business, even excluding the effects of Enron's $3-billion acquisition of Portland General Electric. Electricity dominates the FRS companies' investment base in the other energy line of business and includes conventional electricity generation (mostly in a variety of foreign locales), cogeneration (mainly in the United States), and geothermal power generation (largely in Southeast Asia), with Exxon's production of oil from Canadian tar sands accounting for most of the balance.

Domestic petroleum refining was the focus of the largest drop in capital expenditures of the FRS companies. Capital expenditures in 1997 for U.S. refining operations were down 20 percent, from prior-year expenditures, falling to the lowest level since 1978. The decline in part reflected FRS companies' reduced commitment to U.S. refining in 1997, as Unocal sold their California refining and marketing assets to Tosco Corp., a non-FRS company, and their interest in the Uno-Ven joint refining venture to Petroleos de Venezuela. The decline also reflected Sun Company's exit from the FRS group in 1997. However, for FRS companies with continuing U.S. refining operations, capital expenditures were up five percent.

Environmentally-related projects were a smaller component of capital expenditures than in recent years. By 1997, the FRS companies had largely completed projects related to the Clean Air Act Amendments of 1990 and California's strict air-quality standards, as well as earlier Federal and State environmental quality mandates. Environmental capital expenditures for all the FRS companies' operations were essentially unchanged at $2.3 billion in 1997.

Growth Returns After A Long Absence

During the 1974 to 1981 period of steep oil price escalations, the average size of FRS companies, as measured by the value of total assets on the balance sheet, tripled. Mega-mergers among the FRS companies during the 1982 to 1984 period also added to the asset base of surviving companies. However, from the mid-1980's until 1993, the asset base of the FRS companies, on balance, declined. The FRS companies made outlays of $448 billion for capital and exploratory expenditures during this period, but, at the same time, they were massively divesting themselves of assets. The divestitures of assets, whether by sale, spinoff, or other method, were undertaken mainly to enhance shareholders' value and reduce the elevated debt levels incurred in earlier mergers and takeover battles.

By 1993, FRS companies had greatly reduced their debt and most FRS companies had reduced the scope of their operations to a few core competencies. By 1997, the FRS companies registered rates of growth in their asset base which had not been seen in a decade or so. The sources of growth in the 1993 to 1997 period were foreign oil and gas production, chemicals, foreign refining and marketing, and other energy enterprises (but not coal).

Majors Make Way for Independents in U.S. Petroleum and Natural Gas

The FRS companies did not target U.S. petroleum refining and marketing for growth during the 1993 to 1997 period. In fact, the FRS companies have been reducing their asset base in U.S. refining and marketing in recent years. This retrenchment was, in part, a reaction to the low profitability of these operations in the first half of the 1990's. Seven specialized refiners (i.e., refiners having no upstream oil production) were the purchasers of most of the FRS companies' divested refining and marketing assets. As a result, the ownership structure of U.S. refining and marketing operations has changed noticeably. For example, the share of the seven refiners nearly tripled, to 23 percent, between 1990 and 1997. The bulk of this growth came from purchases of FRS company assets.

Domestic upstream assets of the FRS companies were roughly level over the 1993 to 1997 time span. However, from the oil price crash of early 1986 until 1993, U.S. upstream petroleum operations were, by far, the main area of retrenchment of the FRS companies. While the FRS companies were cutting their domestic upstream commitments they were increasing their foreign upstream investments. The attractions of overseas investment reflected the typically larger deposits of oil and gas to be found outside North America and a general shift to more favorable treatment by oil-producing nations of investment by western energy companies.

As the FRS companies were making massive divestitures of domestic upstream assets, non-FRS companies were increasing their role in U.S. oil and gas production. For example, the non-FRS companies' share of U.S. oil and gas production increased from 39 percent to 44 percent between 1989 and 1993. A large part of this growth came from purchases of assets from FRS companies and a slightly larger part came from reserves added by non-FRS producers' exploration and development efforts.

This trend continued, with two exceptions, as non-FRS companies gained a 47-percent share of U.S. oil and gas production by 1997. First, unlike the prior five years, the non-FRS companies more than replaced their production through additions to their oil and gas reserve base during 1993-1997. Second, acquisitions of cast-off FRS oil and gas properties were much less important as a source of added reserves in the 1993 to 1997 period than in the prior five years.

1. Worldwide Activities of the U.S. Major Energy Companies

Economic Growth and the Investment Environment

The major U.S. energy companies[1] derive the bulk of their revenues and income from petroleum operations, including natural gas production. Most of these companies are multinational, with 39 percent of their net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the companies' financial performance. Developments in chemical markets are also important in that 15 of the 24 major energy companies whose operations are covered in this report have asset commitments in chemical manufacturing. (For a list of these companies, the Financial Reporting System (FRS) companies, see the box entitled "The FRS Companies in 1997.")

Increases in the spread between petroleum product prices received by FRS refiners and oil input prices paid provided the main source of improved financial performance of the FRS companies in 1997 compared to results in 1996 (see Chapter 2, "Financial Developments in 1997"). Also contributing to improved bottom-line results were marginally improved chemical operations and slightly higher natural gas prices and natural gas production in the United States and abroad. Lower oil prices in 1997, however, nearly offset these favorable financial developments.

The FRS Companies in 1997

Amerada Hess Corporation	Fina, Inc.
Amoco Corporation	Kerr-McGee Corporation
Anadarko Corporation	Mobil Corporation
Ashland Oil, Inc.	Occidental Petroleum Corporation
Atlantic Richfield Company (ARCO)	Oryx Energy Corporation
BP America, Inc.	Phillips Petroleum Corporation
Burlington Resources, Inc.	Shell Oil Company
Chevron Corporation	Sonat, Inc.
Coastal Corporation	Texaco, Inc.
E.I. du Pont de Nemours and Company	Union Pacific Resources Group
Enron Corporation	Unocal Corporation
Exxon Corporation	USX Corporation

Demand for petroleum and natural gas is linked to economic growth. Overall, worldwide economic growth remained strong in 1997, with worldwide real Gross Domestic Product (GDP) growing 3.3 percent in 1997, little changed from 1996's 3.4 percent.[2] This apparent stability, however, masks some key changes in regional growth patterns that had effects on oil and gas demand in these areas.

Improvements in economic growth in 1997 were concentrated in western industrialized economies. These areas account for nearly half of the world's oil and gas consumption. The United States real GDP growth was 3.9 percent in 1997, up from 3.4 percent in 1996, and Western Europe's real GDP growth rose from 1.9 percent in 1996 to 2.7 percent in 1997. Latin America, which has increasingly been an FRS company target for marketing petroleum products and natural gas, registered real GDP growth of

5.3 percent in 1997, considerably higher than the 3.6 percent and 0.5 percent rates of 1996 and 1995, respectively.

Falloffs in economic growth were concentrated in the Asia-Pacific area. Japan's backslide into recession was reflected in a weak 0.8-percent growth in GDP in 1997, down from the 4.1-percent rate of 1996 that accompanied a short-lived economic recovery. The devaluations and currency value problems of Thailand, Malaysia, Indonesia, and the Philippines, which began in July, undoubtedly had some role in the slip in the Asia-Pacific (outside Japan) region's GDP growth from 6.6 percent to 5.2 percent. For example, Thailand's GDP declined 0.4 percent in 1997.

The generally strong global economic growth led to a 2-percent increase in worldwide oil consumption between 1996 and 1997. The regional patterns of growth in oil consumption roughly paralleled regional patterns of economic growth. Although the 1997 increase in world oil demand was the largest in the 1990's, world oil prices, as measured by the U.S. refiner acquisition cost of imported crude oil, were down by $2 per barrel. This unusual configuration of consumption and price change reflected an imbalance between demand and supply of oil in world markets.

On the supply side, crude oil production in 1997 was up 3.5 percent over 1996 production. The 2.3-million-barrel-per-day rise in production was the largest since 1986 and was considerably in excess of the 1.6-million-barrel-per-day increment in demand. Step-ups in oil production of 6 percent over 1996 levels by members of the Organization of Petroleum Exporting Countries (OPEC) accounted for most of the added oil supply. Nearly all OPEC members reported production increases, with Iraq registering a doubling of production. Since OPEC quotas had been exceeded by most producers through nearly all of 1997, OPEC increased its members' quotas in November.

Increased oil production was not fully absorbed in part because the end of the 1996-1997 winter and beginning of 1997-1998 winter were relatively mild in the United States and much of Europe. In the United States, for instance, heating degree-days in 1997 were 6 percent below the 1996 level during the key heating months. Developments in Southeast Asia in the second half led to unexpected drops in demand for oil, gas, and goods and services generally, which exacerbated the imbalances in oil supply and demand.

Increasing worldwide inventories of crude oil throughout 1997 reflected the imbalance between demand and supply. The customary worldwide drawdowns of oil stocks in the first and fourth quarters simply did not occur in 1997.[3] Mild winter weather bracketed the year and economic slowdowns in the Asia-Pacific region were clearly underway by the fourth quarter of 1997.

Further downstream, price-cost margins were improving in the United States and Europe during 1997 as crude oil prices declined. Refined product demand in the United States increased 2 percent between 1996 and 1997 with the largest gains registered by the relatively high profit margin transport fuels (motor gasoline, diesel, and jet fuel). The margin between product prices received by U.S. refiners and prices paid for crude oil inputs throughout 1997 generally ran above those of 1996. Demand for light fuels (gasoline and distillate) in foreign areas where FRS companies have significant refining and/or petroleum marketing operations also increased. Asia-Pacific, despite the economic problems following the currency devaluations, which began in July, registered a 4-percent increase in consumption of gasoline and distillates while the comparable increases were 5 percent in Latin America and 1 percent in Europe.

Developments in natural gas markets are also important to the FRS companies' financial performance. For example, in 1997, natural gas production accounted for 38 percent of worldwide upstream revenues for the FRS companies. Overall, natural gas demand in the United States was about flat between 1996 and 1997, but relatively mild winter weather at both ends of 1997 resulted in a 4-percent decline in residential natural gas demand. This weather-induced decline in residential natural gas consumption was offset by a 9-percent increase in natural gas consumption by electric utilities. Utilities had cut back sharply on their gas purchases in 1996 due to tight supplies and steep price increases. The jump in 1997 was a return to earlier levels of natural gas purchases.

Abroad, the FRS companies' natural gas production is concentrated in the Asia-Pacific region, Canada, and Europe. Consumption of natural gas in these areas, on a combined basis, was up 1 percent in 1997 from 1996 consumption.

Natural gas prices at the U.S. wellhead were up 3 percent in 1997 over 1996 prices, slightly above the economy-wide rate of inflation, as supply and demand were generally in balance throughout the year. Outside the United States, natural gas prices were up 1 percent overall, based on FRS companies' financial disclosures. Canadian and European prices were up but natural gas prices in other areas, primarily Asia-Pacific, declined 7 percent.

The developments in oil and gas markets in 1997, on balance, pushed the FRS companies' profits to a second consecutive record level, but barely so. Income from refining and marketing operations benefited greatly from wider price-cost margins and increased sales volumes in response to higher product demand. Worldwide upstream operations yielded income in 1997 that was about even with 1996, as lower oil prices offset gains from increased natural gas revenues. Nevertheless, the profitability of the FRS companies' upstream operations in 1997 was second only to that of 1996 in the post-1986 period.

A majority of the FRS companies produce chemicals. In the 1990's, chemical operations have accounted for about 20 percent of total income from all the FRS companies' lines of business. Chemical earnings tend to be highly cyclical with 1995 being the most recent year of peak earnings. Chemical earnings were down sharply in 1996. In 1997, the FRS companies' chemical operations yielded slightly better results than in 1996, due to revenue growth accompanying the generally strong economic conditions of 1997.

The Companies' Importance to the U.S. Economy

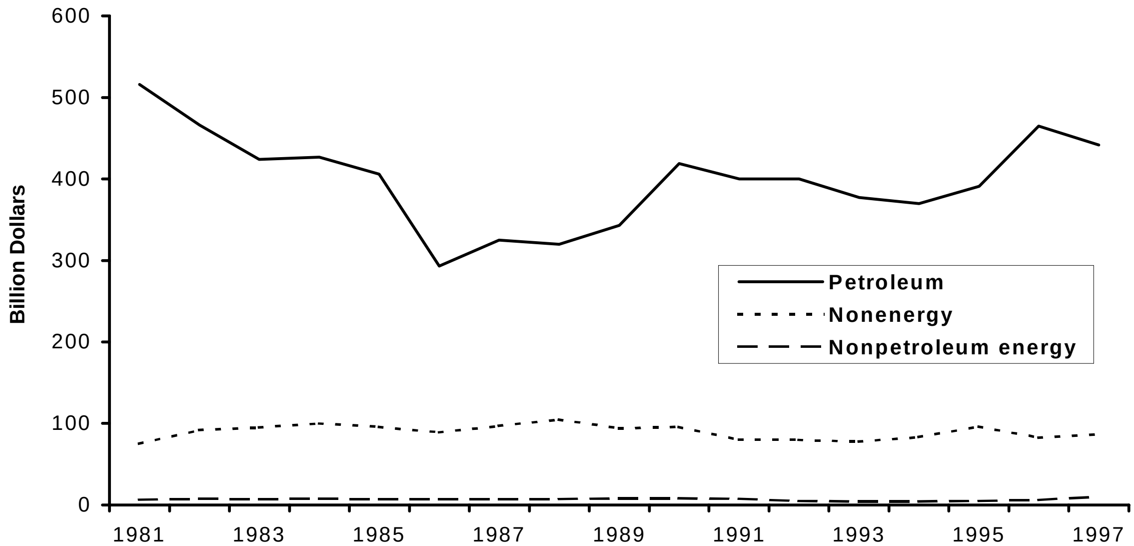
For the reporting year 1997, 24 companies reported their financial and operating data to the EIA on Form EIA-28.[4] These companies (referred to in this report as the FRS companies) occupy a major position in the U.S.[5] economy. In 1997, their sales equaled about half a trillion dollars or about 9 percent of the $5.5 trillion in sales of the *Fortune 500* largest U.S. corporations.[6] Of the top 25 companies (based on sales) on the *Fortune 500* list in 1997, 5 were FRS companies.

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 83 percent, or $438 billion, of allocated operating revenues were derived, from energy sales. Nearly all of these revenues were derived from the companies core petroleum operations (Figure 1). (For the purposes of this report, the petroleum line of business is defined to include natural gas.)

In 1997, the FRS companies accounted for 49 percent of total crude oil and natural gas liquids (NGL) production, 43 percent of U.S. natural gas production, and 59 percent of U.S. refining capacity (Figure 2). The bulk of the FRS companies' assets and new investments were devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy business, mainly chemicals, accounted for about 17 percent, or $87 billion, of the FRS companies allocated revenues in 1997.

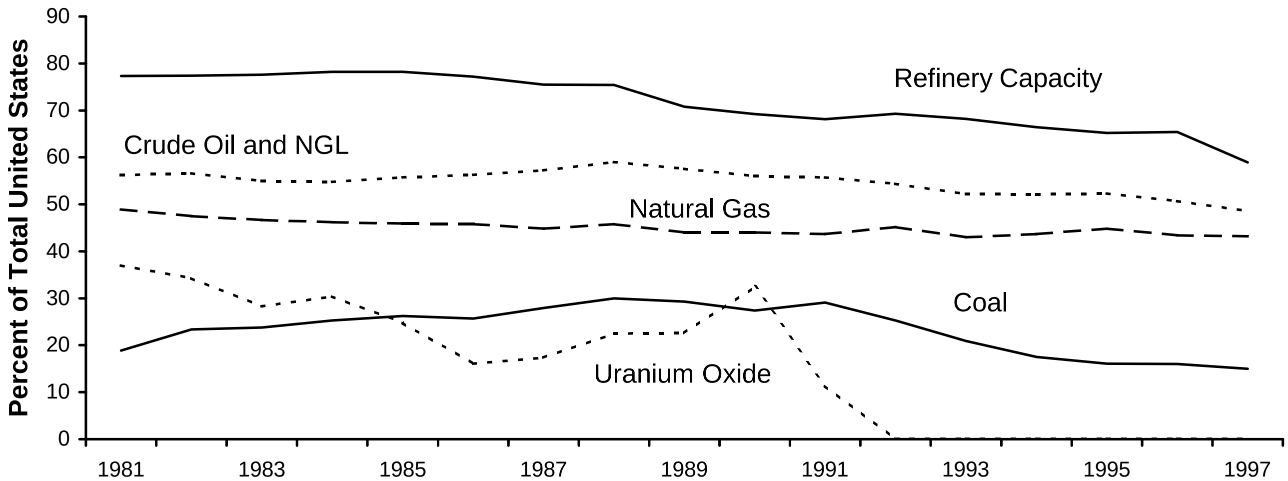
Energy production other than oil and natural gas is a relatively small part of the FRS companies' operations. The combined operating revenues of the coal and other energy operations of the FRS companies totaled $10 billion in 1997, or only 2 percent of allocated revenues. Nonetheless, the FRS companies are significant participants in the coal market, producing 15 percent of U.S. coal in 1997. The FRS companies no longer produce uranium oxide.

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1981-1997



Note: Petroleum includes natural gas.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-1997



Sources: Table B1; Total industry uranium oxide production is from Energy Information Administration, *Uranium Industry Annual 1992* (October 1993).

Endnotes

[1]The companies that reported to the FRS for the years 1974 through 1997 are listed in Appendix A, Table A1. Three of the FRS companies are majority-owned by foreign companies: BP America—100-percent owned by British Petroleum, Fina—79-percent owned by Petrofina, and Shell Oil—100-percent owned by Royal Dutch/Shell.

[2]In this chapter, international energy data were obtained from British Petroleum Company, p.l.c., *BP Statistical Review of World Energy* (London, June 1998); annual U.S. energy industry price and quantity data are from the Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97)(Washington, DC, July 1998); monthly data are from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/09) (Washington, DC, September 1998); GDP data are from the WEFA Group, *World Economic Outlook* (August 1998); and refining margin data are from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380(98/04) (Washington, DC, April 1998).

[3]"Winter Fuels Outlook," *EIA/NASEO Winter Fuels Conference* (October 8, 1998), available on the worldwide web at http://www.eia.doe.gov/neic/speeches/naseo/Wfc98-5/index.htm, slide 13 (December 15, 1998).

[4]Aggregate time series data from Form EIA-28 for 1977 through 1997 and previous editions of this report can be obtained from the EIA (see Contacts, p. ii) or at http://www.eia.doe.gov/emeu/finance/index.html) on paper or diskette.

[5]For purposes of this report, the term "United States" typically includes the 50 States, the District of Columbia, Puerto Rico, and the U.S. Virgin Islands.

[6]The *Fortune 500* is a list of the 500 largest U.S. industrial corporations, ranked by total sales, published annually by *Fortune* magazine.

2. Financial Developments in 1997

Income and Cash Flow

The FRS companies' net income in 1997 of $32.1 billion was at a record level and slightly up from the former record level of 1996 (Table 1). Net income for large U.S. industrial corporations overall, as represented by the Standard and Poor's (S&P) Industrials,[7] was also a record. The profitability of the FRS companies in 1997 continued to keep pace with the historically high rates of return of the S&P group (Figure 3).

Increased price-cost margins for petroleum products and higher natural gas prices in 1997, compared with 1996, were the market-based developments most favorable to the FRS companies' bottom-line results. Strong economic growth in 1997, particularly in the United States, led to gains in the FRS companies' chemical and other nonenergy businesses, as well as adding to petroleum and natural gas demand. Lower oil prices realized by the FRS companies' upstream (exploration, development, and production) operations partly offset the effects of these favorable developments. Reduced interest expense and income tax refunds, mostly from overseas, also favorably affected the FRS companies' financial results.

Cost-cutting has been an important source of earnings enhancement among the FRS companies in the 1990's. Cost-cutting continued to be evident in 1997, but appeared to have had less impact on income than in recent years.

Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 1996 and 1997
(Billion Dollars)

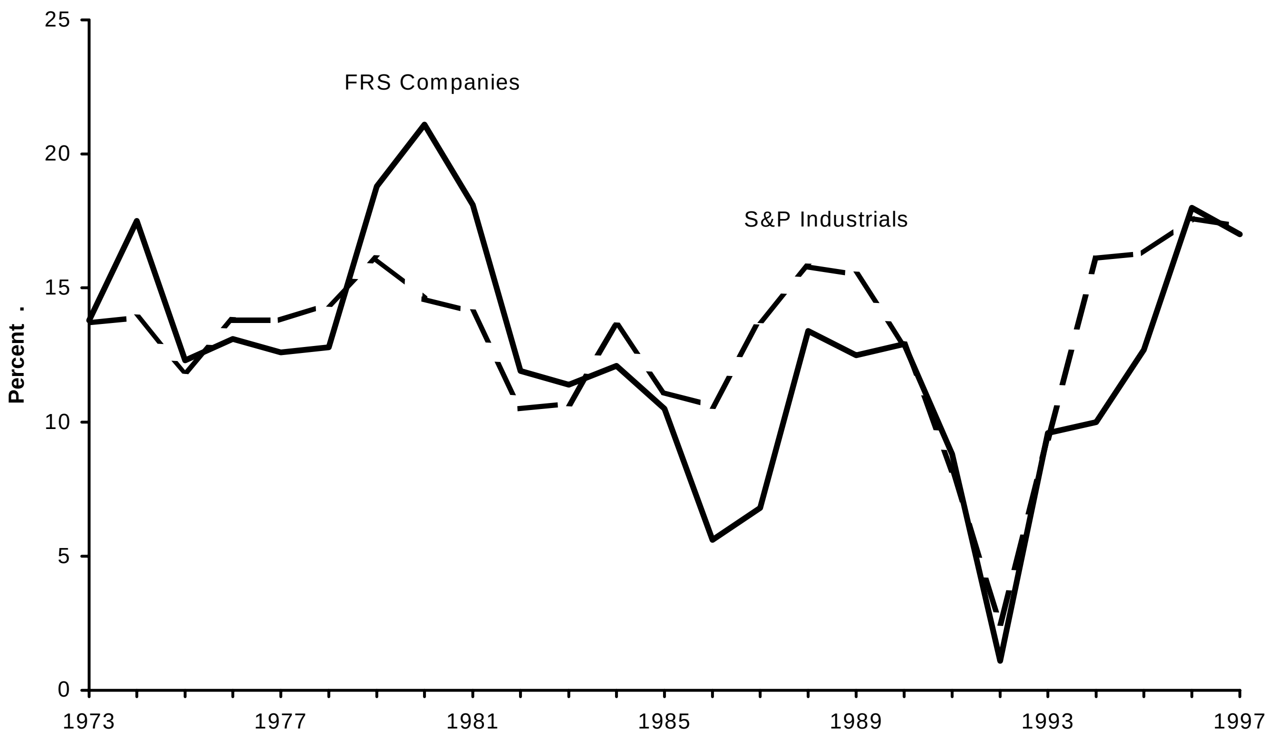
	FRS Companies			S&P Industrials		
Income Statement Items	**1996**	**1997**	**Percent Change 1996-1997**	**1996**	**1997**	**Percent Change 1996-1997**
Operating Revenues	541.4	525.1	-3.0	3,554.2	3,787.0	6.6
Operating Expenses	-492.7	-478.4	-2.9	-3,161.2	-3,352.1	6.0
Operating Income	48.7	46.7	-4.2	392.9	434.9	10.7
Interest Expense	-6.9	-6.4	-7.5	-73.3	-77.1	5.2
Other Revenue (Expense)	10.3	10.5	1.8	20.7	-1.6	-107.7
Income Tax Expense	-20.0	-18.6	-6.9	-121.9	-129.8	6.5
Net Income	32.0	32.1	0.2	218.4	226.4	3.6
Net Income Excluding Unusual Items	30.5	33.9	11.2	NA	NA	

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

NA= not available.

Sources: **FRS Companies**: Energy Information Administration, Form EIA-28 (Financial Reporting System); **S&P Industrials**: Compustat PC Plus, a service of Standard and Poor's.

Figure 3. Return on Equity for FRS Companies and the S&P Industrials, 1973-1997



Sources: **FRS Companies**: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Refining and Marketing Operations Contribute Most to Earnings Growth

Net income from the FRS companies' worldwide refining/marketing operations,[8] excluding unusual items,[9] was up $2.6 billion in 1997, accounting for the bulk of the growth in overall net income (Table 2). Refining/marketing operations in the United States continued to recover in 1997 from a downward trend in profitability in the first half of the 1990's (Table 3). This trend resulted from a deterioration in the margin between refined product prices received by FRS refineries and the price of raw material inputs to refineries. Although FRS refiners made noticeable cuts in their operating costs, these cuts were insufficient to offset worsening price-cost spread. This situation reversed in 1996 as tight petroleum product supplies put upward pressures on product prices. Product price increases outpaced rising crude oil prices, leading to wider margins.

In 1997, price-cost spreads again improved, not from tight supplies but from lower crude oil input prices. Cost-cutting also helped in 1997. The FRS companies managed to resume cuts in refining/marketing operating costs in 1997 after experiencing a rise in operating costs in 1996 (largely due to compliance with environmental requirements).

As a result of these developments, net income (excluding unusual items) from the FRS companies' U.S. refining/marketing operations was up 35 percent between 1996 and 1997 following a 103-percent increase the year before. The profitability of these operations in 1997 was at its highest level since 1989 (Table 3).[10] Nevertheless, the rate of return to U.S. refining/marketing assets remained below the average of petroleum operations overall. (For a detailed discussion of the financial performance of U.S. refining/marketing, see the section entitled "U.S. Refining and Marketing" in Chapter 3).

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 1996-1997
(Million Dollars)

Line of Business	Net Income 1996	Net Income 1997	Net Income Percent Change 1996-1997	Net Income Excluding Unusual Items 1996	Net Income Excluding Unusual Items 1997	Net Income Excluding Unusual Items Percent Change 1996-1997
Petroleum						
U.S. Petroleum						
Production	11,816	11,925	0.9	11,536	11,809	2.4
Refining/Marketing	2,251	3,156	40.2	2,476	3,335	34.7
Pipelines	1,635	1,343	-17.9	1,779	1,884	5.9
Total U.S. Petroleum	15,702	16,424	4.6	15,791	17,028	7.8
Foreign Petroleum						
Production	9,190	9,087	-1.1	8,359	8,376	0.2
Refining/Marketing	1,984	3,583	80.6	2,182	3,935	80.3
International Marine	31	138	345.2	31	138	345.2
Total Foreign Petroleum	11,205	12,808	14.3	10,572	12,449	17.8
Total Petroleum	26,907	29,232	8.6	26,363	29,477	11.8
Coal	458	338	-26.2	283	379	33.9
Other Energy	215	346	60.9	240	336	40.0
Nonenergy	8,032	6,393	-20.4	8,180	8,361	2.2
Total Allocated	35,612	36,309	2.0	35,066	38,553	9.9
Nontraceables and Eliminations	-3,583	-4,227	--	-4,581	-4,657	--
Consolidated Net Income[a]	32,029	32,082	0.2	30,485	33,896	11.2

[a]The total amount of unusual items was $1,544 million and -$1,814 million in 1996 and 1997, respectively.
-- = Not meaningful.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The FRS companies' foreign refining/marketing operations also registered a considerable jump in income and profitability between 1996 and 1997. Net income was up 80 percent and profitability in 1997 rebounded from the 1990's trough of the prior year. The improvement in 1997 reflected higher price-cost spreads in Europe and Latin America which were not fully offset by lower margins in the Asia-Pacific region. Portents of decline in Asia-Pacific petroleum markets were evident in the first half of 1997, even before Thailand initiated a round of currency devaluations in July, as refiners' price-cost margins dipped well below margins that prevailed in the first half of 1996. A similar pattern was evident in the second half of 1997. By contrast, European refining margins for the first half of 1997 were up compared to 1996 and second-half margins registered an even larger increase. (For a detailed discussion of the financial performance of foreign refining/marketing, see the section entitled "Foreign Refining and Marketing" in Chapter 3.)

Table 3. Return on Investment by Line of Business for FRS Companies, 1987-1997
(Percent)

Line of Business	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Petroleum	6.2	7.3	6.7	9.5	7.0	5.6	6.4	5.6	5.7	10.1	10.8
U.S. Petroleum	4.9	6.3	5.8	7.9	4.9	4.4	4.9	5.2	4.0	9.9	10.3
Oil and Gas Production	4.1	2.8	2.9	8.5	5.1	5.9	5.3	5.5	4.4	14.1	12.9
Refining/Marketing	2.9	14.7	11.5	5.1	2.0	-0.4	3.4	3.6	1.0	4.4	6.7
Pipelines	12.8	9.6	10.2	11.2	10.7	8.4	6.4	7.6	9.1	6.9	6.8
Foreign Petroleum	9.5	9.9	8.7	12.5	11.0	7.9	9.2	6.2	8.4	10.6	11.5
Oil and Gas Production	12.4	9.2	8.9	13.1	9.1	8.2	8.6	6.5	9.3	12.8	11.9
Refining/Marketing	4.7	11.6	8.0	11.2	14.6	7.8	10.6	6.1	7.2	6.0	10.5
International Marine	-3.6	6.8	12.4	11.7	15.6	-1.2	1.2	-2.0	-2.5	2.2	11.8
Coal	5.1	6.7	5.0	3.3	8.7	-9.3	7.6	4.0	6.9	9.9	7.2
Other Energy	0.5	-2.5	-2.3	2.6	2.8	1.8	4.1	4.8	6.1	7.9	6.5
Nonenergy	12.2	20.3	17.3	7.8	2.9	2.1	4.7	10.5	19.4	15.0	11.1

Note: Return on investment measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Upstream Oil and Gas Income Remains Near Post-Crash Peak

Oil and gas production is the major source of net income among the FRS companies' lines of business. Accordingly, the profitability of upstream operations has a strong influence on the FRS companies' financial performance. Until 1996, the profitability of these operations, as measured by return on investment, tended to be well below the rates of return realized before the oil price crash of 1986 (Figure 4). In 1996, sharp upswings in oil prices and gas prices lifted returns on the FRS companies' worldwide upstream investments to the highest level in the post-1986 era. In 1997, upstream rates of return were down only slightly from the year before, even though 1997 crude oil prices were $2 a barrel lower than in 1996 (based on the annual refiner acquisition cost of imported crude oil).

Increased oil and gas production by the FRS companies helped to offset the adverse effects of lower oil prices. The companies increased their U.S. natural gas production by 1 percent, between 1996 and 1997, to a 15-year high. Abroad, the FRS companies increased their natural gas production by 4 percent and also set a record for their overseas gas production. Increases in foreign gas production largely came from Asia-Pacific fields, South America, and the North Sea. The FRS companies' foreign oil production in 1997, up 2 percent from 1996, was at a level not seen since the nationalizations of the mid-1970's. The 1997 uptick was largely traceable to increases in offshore oil production in West Africa, including Angola, Equatorial Guinea, Nigeria, and Republic of Congo.

Combined with modest increases in natural gas prices, the resulting boost to upstream revenue from increased production wiped out most of the effects of lower oil prices in 1997. The FRS companies' net income from U.S. oil and gas production, excluding unusual items, was $11.8 billion in 1997, up 2 percent, and foreign upstream net income was unchanged at $8.4 billion (Table 2). (For additional discussion of upstream financial results, see the section entitled "Oil and Gas Production" in Chapter 3.)

Figure 4. Return on Investment in U.S. and Foreign Oil and Gas Production for FRS Companies, 1977-1997

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Chemical Operations Generate Income Gains

The nonenergy line of business is generally a distant second to petroleum as a source of income for the FRS companies. The two components of this line of business, chemicals and other nonenergy, present strong contrasts in the FRS companies' asset commitments. Chemical enterprises have been second only to foreign upstream operations in terms of growth in the FRS companies' asset base in the 1990's. Other nonenergy, which consists of diverse enterprises including construction, mining, primary metals, real estate, and transportation, has been the primary focus of retrenchment among the FRS companies for well over a decade. Accordingly, the contribution of chemical operations to the bottom line has been increasing while the role of diversified businesses has been declining in the 1990's.

Income and profitability in chemical operations tend to be cyclical.[11] Figure 5 indicates that a complete trough-to-trough profitability cycle in the FRS companies' chemical businesses, overall, takes about 10 years to unfold. The sharp decline in the FRS companies' rate of return on their chemical assets in 1996 from the most recent peak in 1995 appeared to be the beginning of another cyclical downswing. However, income from chemical operations in 1997 did not register another steep decline, but, instead, was up 6 percent (Table 4).

Continued strong economic growth, particularly in the United States, increased the demand for chemicals. The FRS companies' chemical revenues were up, though not quite to the peak level of 1995

(Figure 6). Operating cost increases were moderated by lower oil prices which held down feedstock costs. As a result, from 1996 to 1997, chemical margins tended to improve. Although the rise in income from chemical operations was modest, it was widespread. Over two-thirds of the FRS companies who produce chemicals registered increases in income, excluding unusual items. Exxon reported that their 1997 chemical earnings were the second-highest in its history.[12] Some FRS companies (such as Ashland, Mobil, and Shell) reported higher price-cost margins while others (such as Chevron) reported increased sales volumes made possible by earlier capacity expansions.[13] However, Occidental Petroleum offered a caution concerning future chemical profits by noting that their international sales of chemicals were weakened by the economic troubles in the Far East and the strong U.S. dollar in late 1997.[14]

Figure 5. Operating Return on Investment in Chemicals for FRS Companies, 1975-1997

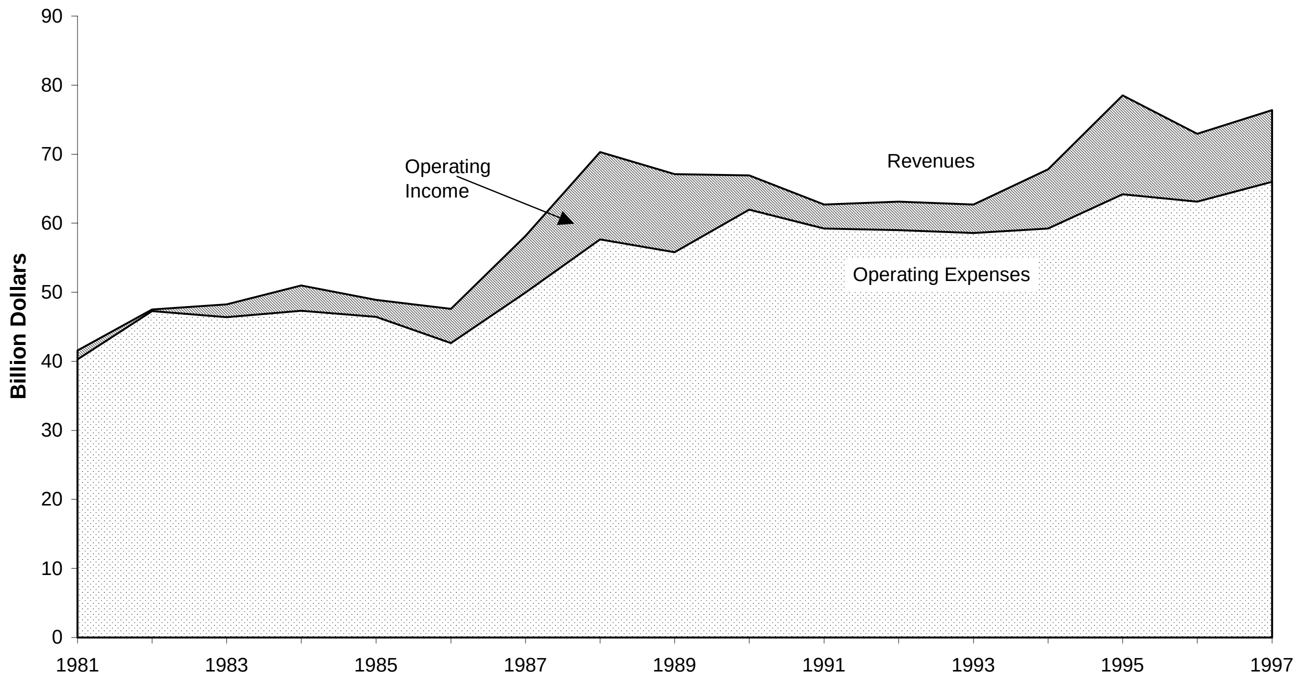
Note: Operating Return on Investment is operating income as a percent of net property, plant, and equipment.
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System); and company annual reports to stockholders.

Table 4. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1996-1997
(Million Dollars)

Segment	1996	1997	Percent Change 1996-1997
Operating Income, Excluding Unusual Items			
Chemicals	9,799	10,428	6.4
Other Nonenergy	609	710	16.6

Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System), except for chemicals segment operating income, which was compiled from company annual reports to shareholders.

Figure 6. Revenues and Operating Expenses for the Chemical Segment for FRS Companies, 1981-1997



Sources: **1981-1986**: Energy Information Administration, Form EIA-28 (Financial Reporting System). **1987-1997**: Company annual reports to shareholders.

The FRS companies' diversified businesses outside energy and chemicals, which are included in the other nonenergy line of businesses, benefited from the generally strong economic conditions of 1997. Income from other nonenergy was up 17 percent between 1996 and 1997 (Table 4). A number of companies reported improved financial results in 1997. USX reported a $285-million increase in income from steel operations "…due primarily to higher average realized steel prices, improved operating efficiencies, and receipt of $40 million in insurance settlements."[15] Exxon's diversified businesses benefited from record copper production in 1997.[16] Unocal's "Carbon and Minerals" business registered a near doubling of revenues and income in 1997 from prior-year levels.[17]

Pipelines, Coal, Other Businesses Also Add to Bottom-Line Improvement

Pipelines

Net income, excluding unusual items, from the FRS companies' regulated pipeline operations was up 6 percent, between 1996 and 1997. This slight gain encompassed rates of return from a variety of pipeline assets. Regulated pipelines can be divided into three components for purposes of reviewing financial performance: natural gas pipelines, the Trans-Alaska Pipeline System (TAPS), and lower-48 liquids pipelines. This disaggregation involves grouping companies whose pipeline assets fall predominantly into one of the categories. The natural gas pipelines group accounted for 59 percent of the FRS companies' total net investment in pipelines in 1997, with the TAPS and other liquids pipelines groups accounting for 21 and 20 percent, respectively.

Interpretations of 1996 and 1997 data for the natural gas pipelines group are somewhat clouded by the addition of Sonat to the FRS survey group, Occidental Petroleum's exit from the natural gas transmission business through the sale of its MidCon subsidiary (completed in early 1998), and reorganizations of midstream natural gas businesses by Enron and Coastal. Nevertheless, financial performance of natural gas pipelines appeared to improve in 1997. Net income, excluding unusual items, was up 27 percent. Coastal, for example, reported an 18-percent increase in income from their regulated pipelines businesses in 1997.[18] Coastal noted that regulated pipeline revenues were higher in 1997 than 1996 and that the company was able to reduce operating costs as well.

The TAPS, which transports crude oil from the north slope of Alaska to the port of Valdez in southern Alaska, experienced another year of revenue decreases due to the continued decline in Alaskan oil production. Pipeline revenue for the TAPS group was down 7 percent between 1996 and 1997. Alaskan oil production was also down 7 percent, the sixth consecutive decline.[19] However, operating costs did not decline as much as revenues, probably due to the large share of fixed costs in running TAPS. Excluding unusual items, pipeline net income for the TAPS group in 1997 was down 8 percent from the prior-year level.

Net income for the lower-48 liquids pipelines group was, excluding unusual items, up an unremarkable 1 percent between 1996 and 1997.

Other Energy

The FRS companies' other energy enterprises continued to register impressive income gains in 1997, with net income reaching a record high $346 million (Table 2). The other energy line of business consists of electric power generation and marketing, cogeneration, Canadian tar sands, and geothermal power production. Ten FRS companies reported income from this line of business in 1997.[20]

All of the component activities in the other energy line of business have contributed to income growth, but electricity-related activity has been the most important contributor. Other energy revenues nearly tripled, to $6.7 billion, between 1996 and 1997. The surge in revenue was largely attributable to Enron's $3.0-billion merger with Portland General in 1997. Additionally, Exxon reported an increase in electricity sales from its four gas-fired power plants that came on line in Hong Kong a year ago.[21] Unocal reported that income increased as a result of a three-plant, 165-megawatt addition to an existing integrated geothermal power unit coming on line in the Gunung Salak region of Indonesia. The addition of these plants brings the total generating capacity of this power unit to 330-megawatts. This unit is now the largest geothermal power unit in Indonesia.[22] The entrance of Sonat to the FRS group also added to revenues in the other energy line of business. Sonat is involved in electric power marketing.

Operating costs were up as well, particularly for Enron, with its sizable addition to operations from the Portland General merger. Project startups also had an effect on costs. For example, Exxon reported that Syncrude (a Canadian affiliate through its 70 percent owned interest in Imperial Oil Limited) began operations to open the Aurora oil sands mine in Canada by 2000. Unocal's expenses increased due to the start-up of its geothermal power plants in Indonesia. Unocal's income was further offset by a contract dispute between its subsidiary, Philippine Geothermal, and the Philippine National Power Corporation. Under the interim agreement, 60 percent of Philippine Geothermal's revenue and related earnings have been deferred pending settlement.[23] Nevertheless, in 1997, overall revenue growth from the FRS companies' other energy businesses outpaced operating cost rises, yielding a fifth successive gain in annual net income.

Coal

The FRS companies' net income from their coal operations, excluding unusual items, was up a healthy 34 percent in 1997 compared to 1996 net income. Increased production by some companies and cost-cutting by others were, on balance, an offset to generally lower coal prices in 1997. For example, Exxon reported increased coal mining productivity, and also stated that "Production from continuing coal mining operations reached a record … ."[24] Also in 1997, "Ashland Coal … reduced its average costs per ton to record levels, enabling it to more than offset the effects of reduced sales prices."[25]

The company-level story of commitment to coal operations is varied. During 1996 Coastal partially exited from the domestic coal industry by selling its western coal assets, which were bought by ARCO for $411 million.[26] ARCO (which only a few months earlier had indicated that its coal operations were one of its primary business areas[27]) and Kerr-McGee[28] each announced in 1998 that they plan to sell their coal assets and exit from the industry. During 1997, Coastal began substituting company-employed miners and operators for contractors in an effort to reduce costs and increase productivity.[29] Although the substitution of company employees for contractors could indicate Coastal's recommitment to coal, it is more likely an effort to "polish" these operations before selling them.

In contrast, in 1997 Chevron acquired a Wyoming mine, expanded its existing western coal operations, and formed coal production joint ventures both in the United States and in Venezuela.[30] Ashland Inc. increased its ownership of Arch Mineral to 54 percent and, in July of 1997, merged the company with Ashland Coal, forming Arch Coal. Arch Coal then agreed to buy ARCO's divested coal assets for $1.4 billion in March 1998.[31] [32]

Cash Flow At Record Level

The FRS companies' cash flow from operations totaled $67.1 billion in 1997, an all-time record, up $2.9 billion from the previous record cash flow of 1996 (Table 5).[33] Patterns of cash flow across lines of business paralleled line-of-business contributions to net income. Downstream petroleum contributed the most to the increase in cash flow, $2.3 billion (pretax), reflecting the strong performance of those operations in 1997. Oil and gas production, which is the largest source of cash flow for the FRS companies, yielded cash flow in 1997 which was nearly even with the prior-year level. Businesses outside petroleum and natural gas produced slightly more cash flow in 1997 than in 1996. The increase in cash flow from nontraceable financial items[34] can be attributed to the FRS companies' $0.5-billion reduction in interest expense in 1997 (Table 1). Most FRS companies continued to reduce their debt levels in 1997, yielding lower interest expense.

Lower tax outlays also contributed to increased cash flow. In 1997, the FRS companies reported $1.6 billion in tax refunds due to tax settlements. The level of refunds more than accounted for the $1.0 billion in added cash flow from lower current taxes. Current taxes represent the amount of corporate income tax deemed payable in the reporting year.[35]

Table 5. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1996-1997
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	1996	1997	Percent Change 1996-1997
Petroleum			
Oil and Gas Production	53.6	52.8	-1.4
Refining, Marketing, and Transport	14.9	17.2	15.3
Coal and Other Energy	1.2	1.3	8.1
Chemicals	13.2	13.6	3.0
Other Nonenergy	1.3	1.3	4.7
Nontraceable	-2.0	-1.9	--
Total Contribution to Pretax Cash Flow[a]	82.2	84.4	2.7
Current Income Taxes	-17.2	-16.2	-6.1
Other (Net)	-0.8	-1.1	--
Cash Flow from Operations	64.2	67.1	4.6

[a]Defined as the sum of operating income, depreciation, depletion, and amortization, and dry hole expense. Excludes unusual items.

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Targets of Investment

The FRS companies' capital expenditures[36] totaled $61.9 billion in 1997 (Table 6), the highest level of capital expenditures since 1984, the year of several mega-mergers between FRS companies (Figure 7).[37] Mergers and acquisitions in 1997 were a much larger component of capital expenditures than in recent years. A few large transactions involving the acquisitions of companies in oil and gas production, electricity, and chemicals accounted for most the added merger and acquisition activity (Table 7).[38]

Onshore Development Activity Leads Upswing in Capital Expenditures

U.S. oil and gas production accounted for half of the upswing in the FRS companies' capital expenditures, between 1996 and 1997 (Table 6). Perhaps the most remarkable feature of this surge in capital expenditures was that it was mainly led by increased spending for U.S. onshore exploration and development, even when the effects of mergers and acquisitions are excluded.

The U.S. onshore has been a long-running target for cutbacks and consolidations among the FRS companies, particularly after the oil price crash of early 1986, which initiated the current era of relatively low oil prices. For example, at the beginning of 1986, the amount of net onshore oil and gas acreage under lease to the FRS companies was 169 million acres, but by 1997 these holdings had been reduced by 66 percent. During the 1992 to 1996 period, exploration and development expenditures[39] directed to onshore U.S. locales were about 40 percent of the pre-1986 level. These trends, however, do not mean that the U.S. onshore does not hold some attractions for the FRS companies.

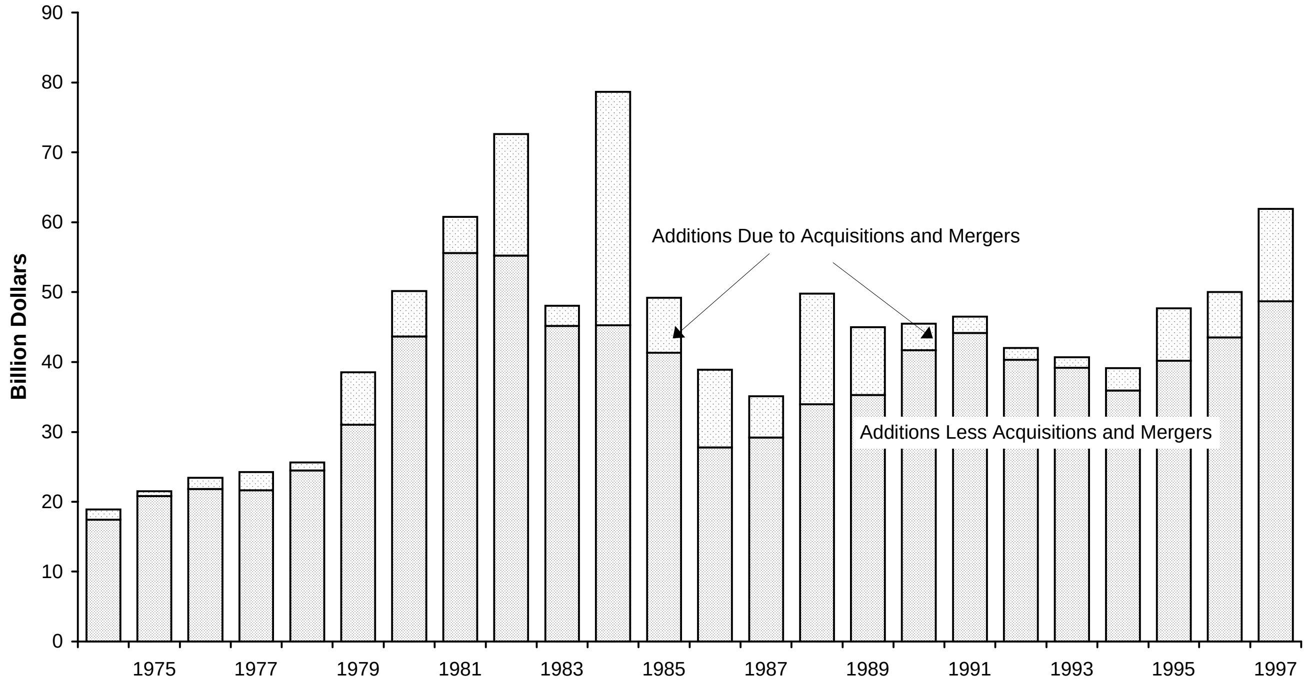
Table 6. Additions to Investment in Place by Line of Business for FRS Companies, 1996-1997
(Billion Dollars)

Line of Business	1996	1997	Percent Change 1996-1997	Percent Change Excluding Mergers and Acquisitions 1996-1997
Petroleum				
U.S. Petroleum				
Production	14.1	20.2	43.2	16.3
Refining/Marketing				
Refining	2.1	1.7	-20.5	-17.6
Marketing	2.1	2.2	7.9	6.4
Transport	0.5	0.7	45.3	45.3
Total Refining/Marketing	4.7	4.6	-1.1	-0.2
Pipelines	1.4	1.7	28.9	49.9
Total U.S. Petroleum	20.1	26.6	31.9	14.4
Foreign Petroleum				
Production	14.7	16.9	14.7	24.1
Refining/Marketing	3.5	3.5	-1.2	-12.9
International Marine	0.1	0.0	-63.5	-63.5
Total Foreign Petroleum	18.3	20.4	11.3	14.9
Total Petroleum	38.5	47.0	22.1	14.6
Coal	0.7	0.4	-40.4	45.6
Other Energy	0.6	2.8	395.5	95.0
Nonenergy				
Chemicals	7.4	9.1	22.6	-2.4
Other Nonenergy	1.2	1.1	-9.8	-9.8
Total Nonenergy	8.6	10.2	18.2	-3.6
Nontraceables	1.6	1.6	-0.6	--
Additions to Investment in Place[a]	50.0	61.9	24.0	--
Additions Due to Mergers and Acquisitions	6.5	13.2	101.9	--
Total Additions Excluding Mergers and Acquisitions	43.4	48.7	12.2	--
Addendum: Environmental Capital Expenditures	2.3	2.3	-1.3	--

[a]Measured as additions to property, plant, and equipment, plus additions to investments and advances.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System), except for environmental capital expenditures, which came from company filings of Securities and Exchange Commission Form 10-K.

Natural gas has been the main onshore attraction. A majority of the FRS companies increased their onshore natural gas production from the low point in 1986 through drilling and acquisitions of producing fields. Expected increases in natural gas demand, stemming from environmental quality concerns and increased use of natural gas by electric utilities, have stimulated natural gas development in the United States. Advancing technologies have lowered the costs of production and replacement of reserves, although technological advances may favor development of large fields in the Gulf of Mexico and outside North America relatively more than onshore natural gas fields.

Figure 7. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-1997



Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System); and company filings of Securities and Exchange Commission Form 10-K.

Tax incentives have also provided a spur to onshore natural gas development. In particular, Section 29 of the Internal Revenue Code, through tax credits, effectively provides a higher-than-market price for natural gas produced from specified nonconventional sources. To qualify for the credit, the gas must be produced from wells drilled before 1993. The largest source of production that receives Section 29 tax credits is coal bed methane, which largely comes from the San Juan Basin in New Mexico but also from Alabama and Wyoming. A few companies have also taken advantage of Section 29 tax credits by producing natural gas from tight sands formations.

In 1997, the FRS companies spent $2.3 billion for onshore gas drilling, a 44-percent increase over 1996 expenditures, yielding 2.4 thousand new wells, 8 percent above 1996 completions and an all-time record.

Drilling for oil in onshore locales was also a target of FRS companies' investment despite the decline in oil prices in 1997. The FRS companies spent a post-1986 record $1.8 billion to drill 3.1 thousand onshore oil wells, 800 more than in 1996. The 42-percent increase in completions was generally widespread, but the bulk of the increase was concentrated among FRS companies with sizable commitments to California oil production, such as Texaco who reported 600 more U.S. well completions in 1997 compared to 1996 completions.[40] Companies operating in areas with significant horizontal drilling activity such as the Austin Chalk formation in Texas and the Williston Basin in North Dakota also registered sizable increases in onshore oil well completions in 1997.

Table 7. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1997
(Million Dollars)

Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
U.S. Oil and Gas Production		
Burlington Resources	Merger with Louisiana Land and Exploration	3,000
Texaco	Monterey Resources	1,400
DuPont (Conoco)	Lobo Trend assets of TransTexas Natural Gas	929
Union Pacific Resources	Highlands Gas Corporation	181
Union Pacific Resources	Castle Energy assets in Rusk County, TX	54
Union Pacific Resources	Laurel Operating Co. assets in Louisiana	54
Occidental Petroleum	Oil and gas producing assets from Suemaur	50
Foreign Oil and Gas		
Amoco	50 percent stake in Empresa Petrolera Chaco, SA (Bolivia) and Pan American Energy	865
ARCO	Investment in LUKARCO	200
Phillips Petroleum	Western Canadian properties from Gulf Canada Resource	165
Burlington Resources	Acreage in the East Irish Sea from BG Exploration and Pr	159
Phillips Petroleum	Assets in Zama/Virgo Basin (Alberta) from Pennzoil	104
Coal and Other Energy		
Enron	Portland General merger	3,000
Enron	Minority interest in Enron Global Power and Pipelines	438
Enron	Lignite reserves from NGC	149
Chemicals		
DuPont	ICI's global polyester intermediates and resins businesses	2,030
DuPont	Protein Technologies International from Ralston Purina	1,903
DuPont	Pfister Hybrid Corn Company	27

Sources: Company annual reports to shareholders and press releases.

Following a large dip in expenditures and drilling in 1992, offshore locales continued to attract large investment outlays from the FRS companies. Technological advances in seismic imaging have greatly increased the success of exploratory drilling offshore (and onshore as well) while engineering advances in platform design and construction and in drilling techniques have made the search for and development of deepwater prospects in the Gulf of Mexico economic. Also, the availability of Federal acreage for bid in the Gulf has provided incentives for offshore exploration and development. The Deep Water Relief Act, which reduces Federal Royalties from deep water production, went into effect in July 1996, and contributed to the attractiveness of deep water prospects. The FRS companies' exploration and development expenditures for offshore projects, most of which are in the Gulf of Mexico, totaled $8.8 billion in 1997 which was $2.1 billion over 1996 expenditures and triple the level of expenditures in 1992.

The FRS companies' offshore efforts in 1997 emphasized oil over gas. Their offshore oil well completions, in 1997, were up 10 percent over 1996 completions, the same annual growth registered over the 1992-1996 period. Natural gas well completions in 1997 were up only 1 percent from the prior year. However, the prior year, 1996, was the culmination of more than a tripling in offshore gas well completions from the low point of 1992.

Oil and gas prospects outside the United States continued to attract FRS companies' investment. The FRS companies' capital expenditures for foreign oil and gas production reached a record $16.9 billion in 1997, up 15 percent from 1996 expenditures (Table 6). The FRS companies spent more on oil and gas exploration and development in 1997, compared to 1996 spending, in each of the foreign regions (Canada, Europe, the Former Soviet Union, Africa, Middle East, Other Eastern Hemisphere, and Other Western Hemisphere) except the Other Eastern Hemisphere. The absence in 1997 of Mobil's 1996 acquisition of Ampolex Ltd. (Australia) for $1.4 billion largely accounted for the drop in expenditures in this region.

The general thrusts of upstream investment in 1997, in both domestic and foreign operations, were a strong expansion of development activity and cutbacks in exploration. Lower oil prices in 1997 undoubtedly played some role in cutbacks in exploration. A more compelling possibility is that earlier exploratory efforts had begun to yield a growing portfolio of areas to bring into production through the development process. These tendencies were strongly evident in the well drilling data. Exploratory wells completed by the FRS companies worldwide in 1997 were down 27 percent, with the United States, Canada, and regions outside North America all registering less exploratory drilling. In contrast, the FRS companies drilled 7.8 thousand development wells worldwide in 1997, the most wells since 1985 and up 25 percent from 1996 drilling. Development drilling for both oil and gas were up in 1997.

The FRS companies' Canadian prospects played a leading role in the upswing in development drilling. This is a surprising development since Canada had frequently been a target of investment cutbacks by the FRS companies in the 1990's: between 1989 and 1996, the FRS companies reduced their Canadian exploration and development expenditures (excluding the effects of mergers and acquisitions) by 52 percent.

Expected growth in exports of natural gas from Canada to the United States is a key factor contributing to the attractiveness of our northern neighbor. For example, Enron[41] is active in developing gas fields in Alberta, Manitoba, and Saskatchewan. New fields under development off the coast of Newfoundland and Nova Scotia are another important factor. Mobil reported that they made their first shipment of oil from the vast Hibernia oil field in December of 1997 with expectations that shipments from the even more remote Terra Nova oil field will follow. Mobil also reported continued progress in the development of the enormous gas fields of the Sable Island area, 125 miles off the coast of Nova Scotia.[42] Opportunities to apply advancing technologies, such as Unocal's horizontal drilling program in Saskatchewan[43] and Exxon's heavy oil projects in Cold Lake, Alberta,[44] have also led to increased investment in Canadian oil development.

Continuing Operators Increase U.S. Downstream Expenditures

For FRS companies with ongoing operations in U.S. petroleum refining and U.S. petroleum marketing, capital expenditures in 1997 for refining were up 5 percent over 1996 expenditures, although Table 6 reports a 20-percent reduction. Interpretation of capital expenditures data for U.S. refining and marketing is strongly affected by two events in 1997. Unocal sold their California refining and marketing assets to TOSCO Corp and sold their interest in the Uno-Ven joint venture to Petroleos de

Venezuela. Sun Company exited from the FRS survey group due to their completed divestiture of oil and gas production operations in 1996.

Excluding Unocal and Sun, the FRS companies' capital expenditures for U.S. refining operations were up a slight 5 percent. The pattern of expenditures across companies reflected a mixture of in-progress refinery upgrading projects and recently completed projects. Half of the FRS refiners reported increased expenditures for U.S. refining operations. For example, BP America reported that they were adding to the capability of their Toledo, Ohio, refinery to process heavy crude oil,[45] while Exxon reported completion of an electrical cogeneration facility integrated with their Baytown, Texas refinery.[46]

Environmentally-related projects appeared to be a smaller component of capital expenditures than in recent years. Environmental capital expenditures by U.S. refiners in 1996 were down more than 60 percent from 1995 expenditures[47] as projects related to the Clean Air Act Amendments of 1990 and California's strict air-quality standards, as well as to earlier Federal and State environmental quality mandates, were largely completed. Data on domestic refiners 1997 environmental capital expenditures are not yet available but the "Addendum" in Table 6 indicates that FRS environmental capital expenditures for all operations were essentially unchanged between 1996 and 1997.

FRS companies with ongoing commitments to U.S. petroleum marketing increased their capital expenditures for these operations by 18 percent between 1996 and 1997. The 8-percent increase shown in Table 6 includes Sun and Unocal. Several FRS companies significantly enlarged their directly-owned gasoline marketing networks in 1997. The FRS companies added nearly 600 company-operated retail gasoline outlets in 1997 (excluding Sun and Unocal), a 7-percent increase from the prior-year's station count. For example, Amoco reported adding 350 outlets and Amerada Hess acquired 66 retail outlets in Florida.[48]

It should be noted that the 45-percent increase in capital expenditures for refining/marketing transport (mainly trucks, barges, and intrastate pipelines) was largely the result of a reorganization by Union Pacific Resources (UPR). UPR established their natural gas gathering, processing, trading, and marketing operations as a separate business, reclassifying nearly $400 million in property, plant and equipment from U.S. oil and gas production to downstream transport.[49] Excluding UPR, as well as Sun and Unocal, capital expenditures for refining/marketing transport were down 20 percent, mainly due to USX's sale of their Delhi Gas Pipeline subsidiary to Koch Industries in 1997 (Table 8).

The uptick in interest in regulated pipelines, as evidenced by the 29-percent increase in capital expenditures (Table 6), was largely traceable to developments in natural gas pipelines rather than liquids pipelines. The same growth in U.S. natural gas demand, both recent and expected, that has driven upstream investment to heightened levels has had an expansive effect on natural gas pipeline investments. Enron reported an increase in capital outlays of $162 million for expansion of their interstate natural gas transmission network, particularly in the upper Midwest,[50] and Coastal Corporation reported that their capital expenditures (including investments in partially-owned subsidiaries) for natural gas pipelines and processing were nearly $100 million higher in 1997.[51] Also affecting the amount of reported capital expenditures for natural gas pipelines was Occidental Petroleum's treatment of their Mid Con subsidiary as a discontinued operation in 1997, pending its final sale in early 1998, which meant that no capital expenditures were reported for those operations. Also, beginning with the 1997 reporting year, Sonat, a large, vertically integrated natural gas company with substantial natural gas pipeline investments, was added to the FRS survey group. On balance, the net effect of these two developments was to increase the FRS companies' reported capital expenditures for pipelines by nearly $100 million.

Table 8. Major Divestitures, Ownership Sales, and Related Transactions by FRS Companies, 1997
(Million Dollars)

Company	Transaction	Reported Value of Transaction
Unocal	Sold West Coast refining, marketing, and associated transport assets to Tosco	1,797
Amoco	Sold onshore oil and gas properties in the Rocky Mountains, Mid-Continent, Gulf Coast, and San Juan Basin (New Mexico) regions, and Amoco Gas Company to more than 8 buyers.	1,500
Arco	Sold remaining stock in Lyondell Petrochemical	988
USX	Sold Delhi Gas Pipeline to Koch Industries	752
Texaco	Sold remaining chemical assets to Huntsman	600
Ashland	Sold Blazer Energy (Ashland's U.S. oil and gas subsidiary) to Eastern Group	566
Chevron	Gulf Oil Great Britain (U.K. refining/marketing assets) to Royal Dutch / Shell	325(est.)

Sources: Company annual reports and press releases.

Abroad, the apparent stability of downstream expenditures, at $3.5 billion in 1996 and 1997, masks some significant shifts in asset deployment. The most notable development was Mobil's formation of an alliance with British Petroleum which combined the companies' European refining and marketing assets, with Mobil as a minority (less than 50 percent) shareholder (for additional discussion of alliances, see the Highlight entitled "BP-Mobil Alliance of European Refining Operations" in Chapter 3). Due in part to some technical accounting transitions, Mobil reported a reduction of $233 million in capital expenditures for European refining and marketing. [52] Partially offsetting Mobil's reduction in expenditures was Texaco's capital outlays of $484 million for their foreign downstream operations in 1997, up $130 million from 1996. [53] Texaco reported large increases in the number of their gasoline outlets in the United Kingdom, Denmark, and South America.

Business Ventures Outside Petroleum and Natural Gas Also Attract Investment

Chemicals

Chemical operations are among the core businesses of 15 of the FRS companies. Capital expenditures for chemical operations are in some years second only to expenditures for worldwide oil and gas production in amount, which was the case in 1997. In 1997, the FRS companies' capital expenditures for chemical manufacturing totaled $9.1 billion, 23 percent above 1996 expenditures (Table 6).

The large increase in spending can be traced to acquisitions of existing operations by DuPont (Table 7). DuPont's acquisitions were in support of its shift in corporate strategy to emphasize life sciences as a core business. [54] DuPont's announced intention to spin off its Conoco subsidiary to shareholders following a planned initial public offering for newly issued shares in Conoco late in 1998, is also part of their shift in strategy. When the spinoff of Conoco is accomplished, DuPont will have exited the energy business. DuPont entered the energy business through their acquisition of Conoco in late 1981. Unlike DuPont, other FRS chemical manufacturers, overall, reduced their capital expenditures in 1997, by 10 percent, from 1996 levels. This reduction reflects the fall in the profitability of chemical manufacturing from its peak profitability in 1995 (Figure 5).

Coal

Acquisitions also had a large effect on FRS companies' reported capital expenditures for their worldwide coal operations, which are mainly in the United States. In 1996, ARCO purchased a 65-percent interest in Canyon Fuel Company from Coastal (another FRS company) for $411 million. Excluding this acquisition, the FRS companies' $0.4 billion in capital expenditures for coal operations in 1997 represented a 46-percent increase in spending. Although several FRS companies have exited the coal business in the 1990's, those remaining in the coal business are continuing to maintain or increase their coal production capability. For example, the FRS companies increased their overall U.S. coal production capacity by 12 percent between 1996 and 1997 (Table B34). Of course, recent increased expenditures and capacity additions might reflect enhancements to coal assets directed toward making these assets more salable in the future.

Other Energy

The other energy line of business registered the steepest growth in capital expenditures between 1996 and 1997 among the FRS lines of business. Enron's merger with Portland General, an Oregon-based electrical utility, accounted for most of the increase in expenditures. Even excluding the effects of mergers and acquisitions, capital expenditures for other energy enterprises nearly doubled. During the 1990's, electricity generation and cogeneration became a target of investment for a small minority of the FRS companies, most prominently Enron and Coastal (for a further discussion of FRS company involvement in electricity businesses, see the section entitled "Electricity Restructuring Attracts the U.S. Majors" in Chapter 4). The balance of other energy assets consists mainly of Canadian oil sands extraction and geothermal power generation, largely in Southeast Asian locales. The companies principally involved in these latter activities in total increased their capital expenditures for other energy development by 45 percent, indicating favorable outlook for these alternative sources of energy. As noted in the section entitled "Corporate Growth Returns After a Long Absence" in Chapter 4, other energy, though only a small fraction of the FRS companies' total asset base, grew more rapidly in the 1990's than any other line of business.

Other Nonenergy

In contrast, the other nonenergy line of business, which encompasses a variety of enterprises outside energy and chemicals, has been the leading target of retrenchment in the 1990's. Most of the asset divestitures in this area in the 1990's have been made as FRS companies consolidated other businesses to core areas in which they view themselves as having competitive advantages. Capital expenditures for other nonenergy businesses hit a 20-year low in 1997, as the FRS companies made an overall 10-percent cutback from 1996 expenditures.

Cash Allocated to Manage Debt and Benefit Shareholders

Cash flow from operations and capital expenditures are, by far, the largest source and use, respectively, of the FRS companies' funds (Table 9). Other sources and uses of funds are important in the FRS companies' efforts to increase shareholder value and manage their debt.

The FRS companies issued $7.2 billion more in long-term debt (i.e., debt securities with a maturity of one year or more) in 1997 than in the prior year, a 67-percent increase (Table 9). The increase in long-term debt was largely traceable to three companies. DuPont issued $6.5 billion in long-term debt in 1997, up $3.3 from their 1996 level, in connection with acquisitions and stock repurchases. In 1997,

Table 9. Sources and Uses of Cash for FRS companies, 1996-1997
(Billion Dollars)

Sources and Uses of Cash	1996	1997	Percent Change 1996-1997
Main Sources of Cash			
Cash Flow from Operations	64.2	67.1	4.6
Proceeds from Long-Term Debt	10.7	17.9	67.2
Proceeds from Disposals of Assets	10.9	9.3	-14.8
Proceeds from Equity Security Offerings	1.2	1.5	28.7
Main Sources of Cash			
Additions to Investment in Place	50.0	61.9	24.0
Reductions in Long-Term Debt	18.9	19.8	4.7
Dividends to Shareholders	15.6	16.9	8.7
Purchase of Treasury Stock	1.3	7.9	508.9
Other Investment and Financing Activities, Net	1.0	10.1	--
Net Change in Cash and Cash Equivalents	2.3	-0.6	--

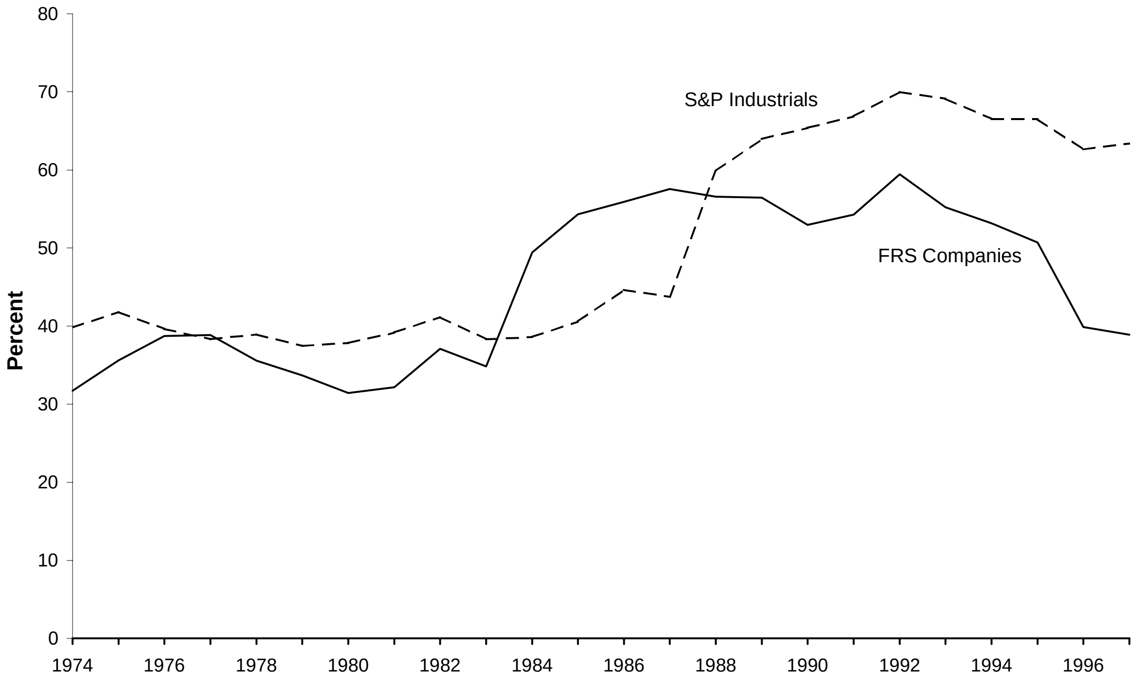
-- = Not meaningful.
Note: Sources minus Uses plus Other Investment and Financing Activities (Net) may not equal Net Change in Cash and Cash Equivalents due to independent rounding.
Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

DuPont made acquisitions of companies and assets totaling $4.9 billion in value and made $1.7 billion in repurchases of their common stock. Enron, who merged with Portland General in a transaction valued at $3.0 billion, reported issuing $1.8 billion in long-term debt in 1997, up $1.4 billion.[55] Finally, the addition of Sonat to the FRS survey group and the deletion of Sun had a net effect on the reported issuance of long-term debt of $1.9 billion.

Although long-term borrowings were up sharply in 1997, the FRS companies' debt repayments of $19.8 billion (Table 9) outpaced them. As a result, the role of debt in the FRS companies' balance sheets continued to decline, though slightly, in 1997. As Figure 8 shows, the FRS companies' ratio of long-term debt to stockholders' equity (the book value of ownership) reached a 14-year low.

The FRS companies used part of their record cash flow to enhance shareholder value through repurchases of their own common stock in 1997. Sixteen FRS companies reported stock repurchases in

Figure 8. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-1997



Sources: **FRS Companies**: Energy Information Administration Form EIA-28 (Financial Reporting System). **S&P Industrials**: Compustat PC Plus, a service of Standard and Poor's.

1997, up from twelve in 1996, totaling $7.9 billion, a six-fold increase from 1996. Exxon reported the largest repurchase, $2.2 billion, as the company expanded their repurchase program in 1997.[56] Amoco initiated a 2-year, $2.0 billion buyback program in 1997 by repurchasing $1.4 billion of their common shares.[57] As noted previously, DuPont made outlays of $1.7 billion for their shares in order to offset dilution of stock values resulting from acquisitions and the company's compensation program.

The primary form of payouts to shareholders is cash dividends. The FRS companies paid out $16.9 billion in dividends in 1997, their eighth consecutive annual increase.

Endnotes

[7] The Standard and Poor's Industrials is a well-recognized database that includes nearly 400 of the largest U.S. industrial companies. In 1997, 19 of the FRS companies were included in the S&P Industrials. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.

[8] Line-of-business profit measures should be distinguished from measures that reflect company-wide results because the former reflect only allocated income, expense, and asset items. Two measures of income are presented: *operating income* and *contribution to net income*. Operating income by line of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amoritization) for a line of business. Contribution to net income equals operating income plus income from unconsolidated affiliates and gains on disposal of property, plant, and equipment less income taxes imputed to the line of business and excludes certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a company wide net income figure and line-of-business contributions to net income (see Appendix A for further discussion).

[9] Unusual items are composed of gains and charges recognized in a company's income statement that are of a non-recurring nature and generally unrelated to current operations. These items include effects of accounting changes, litigation settlements, gains and losses from large divestitures of assets, provisions for the cost of restructuring, and provisions of reserves for future liabilities.

[10] Return on investment (ROI) for a line of business is net income divided by net investment in place. Net investment in place is defined as the book value of net property, plant, and equipment plus investments and advances to unconsolidated affiliates. Line-of-business ROI is based on historical costs and measured ex-post average profitability, not marginal or prospective rates of return.

[11] For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, comparable disclosures in the Form EIA-28 from 1981 through 1986. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 1997. Revenues and operating income for the other nonenergy segment after the 1986 reporting year were obtained by subtracting the publicly disclosed chemical segment values from the nonenergy line-of-business values reported on Form EIA-28.

[12] Exxon Corp., *1997 Annual Report*.

[13] Ashland Oil, Inc., *1997 Annual Report*; Mobil Corp., *1997 Annual Report*; Shell Oil Co., *1997 Annual Report*; Chevron Corp., *1997 Annual Report*.

[14] Occidental Petroleum Corp., *1997 Annual Report*.

[15] USX Corp., *1997 Securities and Exchange Commission Form 10-K*, p. U-52.

[16] Exxon Corp., *1997 Annual Report*.

[17] Unocal Corp., *1997 Annual Report*.

[18] Coastal Corporation, *1997 Annual Report*.

[19] Energy Information Administration, *Monthly Energy Review*, September 1998, DOE/eia-0035(98/09) (Washington, DC, September 1998), Table 3.2a.

[20] In addition to Texaco's investments in cogeneration, the company also has a patent on coal gasification. (Texaco Corporation, *1997 Annual Report*, p. 22).

[21] Exxon Corp., *1997 Annual Report*, p. 19.

[22] Unocal Corp., *1997 Annual Report*, pp. 20 and 26.

[23] Unocal Corp., *1997 Annual Report*, p. 26.

[24] Exxon Corporation, *1997 Annual Report*, p. 19.

[25] Ashland Inc., *1997 Annual Report*, p. 63.

[26] ARCO held a 65-percent share of a joint venture with Itochu Corp that bought Coastal's western coal assets for a total of $615 million. See Jeff Cole, "ARCO , in an About-Face, Seeks to Spin Off Or Sell All Its Coal -Mining Operations," *The Wall Street Journal* (April 2, 1997), p. A4.

[27] "Atlantic Richfield To Sell Division," Associated Press (March 23, 1998).

[28] " Kerr-McGee's Board OKs Plan To Exit Coal Operations," Dow Jones Newswires (January 27, 1998).

[29] Coastal Corporation, *1997 Annual Report*, p.22.

[30] Chevron Corporation, *1997 Annual Report*, p. 22.

[31] ARCO retains a 1-percent share of the operating subsidiary of Arch Coal with Arch holding the remaining 99 percent. See Atlantic Richfield Corporation, "ARCO, Arch Coal Reach Agreement on Sale of ARCO's U.S. Coal Assets," news release (March 23, 1998).

[32] Subsequently, in July of 1998, Ashland indicated its intention to divest itself of control of Arch Coal, carrying it as an unconsolidated affiliate, but market conditions through late 1998 have prevented the sale.
"Ashland - Arch Coal Shares: Cites Market Conditions," Dow Jones Newswires (August 11, 1998).

[33] Cash is defined as currency, demand deposits, and interest-bearing assets of less than 30 days maturity. Generally, cash flow from operations is computed by adding to (subtracting from) net income those cost (revenue) items that did not actually involve an outlay (receipt) of cash. The largest of these non-cash items is the cost of depreciation, depletion, and amortization. Also, outlays (receipts) of cash that were recognized as non-cash items in previous income statements (e.g., provisions for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.

[34] Nontraceable items are those revenues, costs, assets, and liabilities that cannot be directly attributed to a line of business or that cannot be assigned to a line of business by use of a reasonable allocation method developed on the basis of operating level realities.

[35] For income statements, income tax expenses are divided into current taxes and deferred taxes. Basically, deferred taxes originate because of timing differences in reporting revenue and expense for financial reporting and tax reporting. Financial reporting attempts to match items of income and expense in the periods in which they occur. Tax reporting may permit different timing for recognizing revenues and deducting expenses. For example, faster writeoffs of depreciable properties are permitted under tax laws while they may not be acceptable under financial accounting principles. Accelerated writeoffs result in lower taxable income and thus lower tax liability in the year taken. In future periods, however, taxable income and income taxes payable may be higher than pretax income for financial reporting purposes because the timing differences between tax and financial reporting are reversed.

[36] To the extent possible, capital outlays are measured by additions to investment in place, which are defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances. In 1997, additions to PP&E accounted for 88 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, capital outlays are sometimes measured solely by additions to PP&E.

[37] In August 1981, E. I. DuPont de Nemours and Company acquired Conoco, then an FRS company, for $7.8 billion. In March 1982, USX Corporation (then U.S. Steel) acquired Marathon Oil, an FRS company, for $5.9 billion. In a transaction between two FRS companies, Occidental Petroleum acquired Cities Service Company for $4 billion in September, 1982. In February 1984, Texaco acquired Getty Oil for $10.2 billion in an intra-FRS company merger. The largest U.S. corporate merger up to March 1984, occurred when Chevron (then Standard Oil of California) purchased Gulf Oil, an FRS company, for $13.3 billion. Finally, in March 1984, Mobil acquired Superior Oil for $5.7 billion in an intra-FRS company transaction.

[38] Figure 7 and Table 6 show the value of property, plant and equipment, and investments and advances added to the companies' books as a result of acquisitions rather than the value of the transactions. The reported value of an acquisition shown in Table 7 is generally the cash outlay and can differ from the effect on additions to investment in place due to assumptions of liabilities and goodwill assets acquired.

[39] Exploration and development expenditures include both capital expenditures (additions to PP&E) and exploration expenses. In 1997, capital expenditures were 87 percent of exploration and development expenditures.

[40] Texaco Inc., *1997 Securities and Exchange Commission Form 10-K.*

[41] Enron Corp., *1997 Securities and Exchange Commission Form 10-K.*

[42] Mobil Corp., *1997 Annual Report*.

[43] Unocal Corp., *1997 Annual Report*.

[44] Exxon Corp., *1997 Financial and Operating Review*.

[45] British Petroleum plc, *1997 Securities and Exchange Commission Form 20-F*, p. 47.

[46] Exxon Corp., *1997 Annual Report*.

[47] American Petroleum Institute, *Petroleum Industry Environmental Performance, Sixth Annual Report* (Washington, DC, May 1998), p. 54.

[48] Amoco Corp., *1997 Annual Report*; Amerada Hess Corp., *1997 Annual Report*.

[49] Union Pacific Resources Group, *1997 Annual Report*.

[50] Enron Corp., *1997 Annual Report*.

[51] Coastal Corporation, *1997 Annual Report*.

[52] Mobil Corp., *1997 Fact Book*.

[53] Texaco Inc., *1997 Financial and Operational Supplement*.

[54] E.I. DuPont de Nemours and Company, *1997 Annual Report*.

[55] Enron Corp., *1997 Annual Report*.

[56] Exxon Corp., *1997 Annual Report*.

[57] Amoco Corp., *1997 Annual Report*.

3. Behind the Bottom Line: Company Strategies and Market Developments

Foreign Refining and Marketing

Large Increase in Foreign Downstream Earnings Masks Divergent Regional Performance

Foreign refining/marketing earnings for 1997 almost doubled, surpassing all but two levels occurring since 1977: the 1991 Persian Gulf War (that led to unusually high refining margins), and the oil price escalations of 1979 to 1980. Profitability was also at a post-Persian Gulf high (Figure 9). Overall earnings for foreign refining/marketing increased 80 percent to $3.9 billion, excluding unusual items (Table 10). However, the surge in earnings does not show several important regional differences for the FRS companies.

Figure 9. Return on Investment in Refining/Marketing for FRS Companies, 1977-1997

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The FRS companies' foreign refining/marketing earnings are derived from two sources: unconsolidated affiliates and consolidated operations. The corporate parent of an unconsolidated affiliate owns 50 percent or less of the affiliate, and therefore does not directly control the affiliate. In essence, the unconsolidated affiliate is more of a property, or a holding, of the parent corporation, rather than a company which the parent actually runs. The effect on financial operations of an unconsolidated affiliate can only be seen on the corporate parent's income statement, where the parent's proportional

Table 10. Foreign Refining/Marketing Financial Items for FRS Companies, 1996-1997
(Million Dollars)

Item	1996	1997	Percent Change 1996-1997
Refined Product Revenues	133,476	136,709	1.0
Net Income from Consolidated Operations [a]	1,177	2,964	151.8
Net Income from Unconsolidated Affiliates [a]	1,005	971	-3.4
Net Income [a]	2,182	3,935	80.3

[a] Excludes unusual items.
Source: Energy Information Administration, Form EIA-28, (Financial Reporting System).

share of the affiliates' net income is reported. Conversely, a fully consolidated affiliate is directly controlled by the parent corporation (although it could be owned by several companies, with the parent corporation owning more than 50 percent). In addition, all operating and financial information about a fully consolidated affiliate (such as revenues, costs, and asset values) is reported in the public financial disclosures of the parent corporation.

Historically, the operations of FRS companies' unconsolidated affiliates have been mainly in the Asia-Pacific region. Nearly 60 percent of unconsolidated affiliate capacity is located in Asia-Pacific with about 30 percent located in Europe and the balance in Africa and the Middle East (Table 11). However, this profile changed slightly in 1997 as a result of the alliance of Mobil/BP European downstream operations. Under the merger agreement, Mobil contributed its European refining/marketing operations in exchange for a 30-percent ownership share in the alliance (see the Highlight entitled "BP-Mobil Alliance of European Refining Operations").

Conversely, for consolidated operations, the regional proportions are nearly reversed: 50 percent of capacity is located in Europe, with the remaining capacity disbursed among the Asia-Pacific region (25 percent), Latin America and Canada (each with a 10-percent share). Consequently, movements in consolidated income will tend to reflect European operations while equity income will be reflective of developments in the Asia-Pacific petroleum markets.

Table 11. Foreign Refining/Marketing Refining Capacity for FRS Companies, 1996-1997
(Thousand barrels per day)

Region	1996 Consolidated Operations	1997 Consolidated Operations	Change 1996-1997	1996 Unconsolidated Operations	1997 Unconsolidated Operations	Change 1996-1997
Europe	2,328	2,006	-322	414	613	199
Asia	886	1,065	179	1,290	1,083	-207
Latin America	412	407	-5	10	10	0
Canada	390	390	0	0	0	0
Other	0	112	112	304	192	-112
Total Operations						
Consolidated	4,016	3,980	-36	-	-	
Unconsolidated	-	-		2,018	1,898	-120

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System); Companies Annual Reports and Securities and Exchange Commission 10-K Form.

HIGHLIGHT: BP-Mobil Alliance of European Refining Operations

The BP and Mobil European alliance that was announced in February 1996 was essentially completed by year-end 1996. In 1997, Mobil and British Petroleum's European downstream alliance began operating (British Petroleum is the UK parent of the FRS company, BP America). The joint venture is a partnership of both companies' European refining and marketing operations in 43 countries where the two separate companies previously operated. To date, all of the refining/marketing operations have been converted to the partnership, except for small operations in two countries (Cyprus and Russia) where the conversion will be completed in 1998. BP now operates a majority of the refineries, and all gasoline stations have been rebranded with the BP logo.

Other company assets in Europe are excluded from the merger (international aviation, marine, crude oil trading and shipping activities). Under the terms of the agreement, the fuel and lubricant operations were realigned, allowing the companies to have separate ownership interests in each of the 43 countries. Mobil gained a controlling interest of 51 percent in the lubricants business. BP has a 70-percent interest in the fuels business, (making Mobil's interest in the fuels operations an unconsolidated affiliate for reporting purposes). The company with the controlling interest will manage and operate each business.

The motives for the alliance appeared to be achieving efficiencies and reducing costs. Weak refining margins and a very competitive retail market have been chronic problems in European petroleum markets. According to BP's chief executive, John Browne, "the European downstream operations of our two companies are uniquely complementary. Bringing them together will produce efficiencies through sharing cost, eliminating duplication and achieving major economies of scale ... the marriage ... will result in joint annual pre-tax savings of $400m to $500m within three years."[a]

The merger resulted in a $5-billion downstream operation (BP assets worth $3.4 billion and Mobil assets worth $1.6 billion) with annual sales of $20 billion.[b] The BP/Mobil joint venture created a top tier European operation, now the largest supplier of European lubricants with an 18-percent share. In addition, it has captured a 12-percent share of the European retail fuels market, improving the competitive position which BP and Mobil held before the merger. Previously, BP's European refining capacity was 825,000 barrels a day (b/d) and Mobil's was 550,000 b/d. However, taken together, the companies have a 1.4 million b/d refining capacity, trailing Exxon (at 1.7 million b/d) and Royal Dutch/Shell (at 1.6 million b/d). Other competitors in the area are Phillips (with a refining capacity of 44,000 b/d) and Texaco (with a refining capacity of 25,000 b/d). Chevron was also previously in the European area (with a refining capacity of 157,000 b/d), but the company ceased being a competitor when they exited the European market by selling off their single European refinery (in Wales) and all their gasoline stations (in the UK).[c]

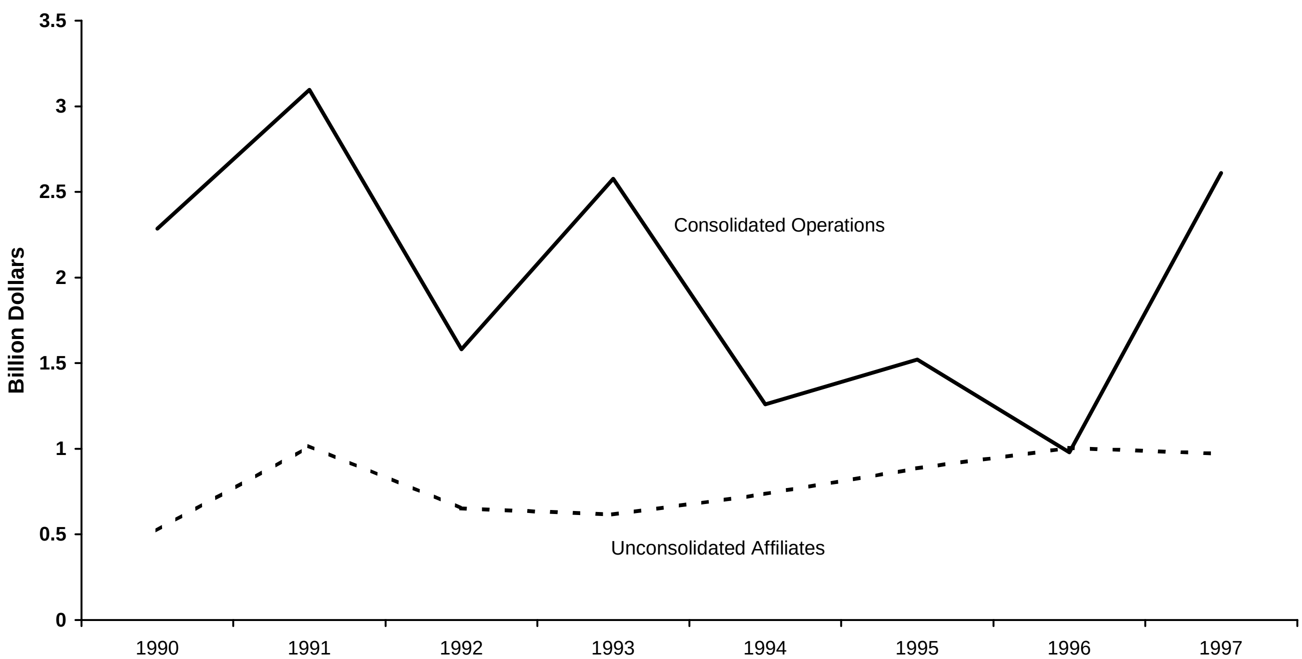
In November 1997, BP/Mobil announced a major restructuring of its lubricants refining business. BP's stand-alone lube refinery at Llandarcy, South Wales will be closed in 1998 as a result of the oversupply of lubricants in Europe. Three European lube refineries, the Gravenchon and Dunkirk operations in France, and the refinery in Hamburg, Germany, will be streamlined.[d] In addition, the merger will result in the reduction of the combined company workforce by 2,700 positions with 1,000 positions being dropped from Mobil's personnel.[e]

[a] Mobil Corporation, *1997 Annual Report*, p. 42; and *1997 Supplement to the Annual Report*, pp. 42, 59 and 60; BP Corporation, *Annual Report on Form 20-F 1997*, pp. 19; "New Giant: BP/Mobil Tie up Downstream," *Platt's Oilgram News* (March 1, 1996), p. 1.
[b] "New Giant: BP/Mobil Tie up Downstream," *Platt's Oilgram News* (March 1, 1996), p. 1.
[c] "Mobil, BP agree to massive merger of holdings in European Downstream British Petroleum," *The Oil Daily* (March 1, 1996), pp. 1 and 2.
[d] Mobil Corporation, *1997 Annual Report*, p. 42; and *1997 Supplement to the Annual Report*, pp. 42 and 60; and BP Corporation, *1997 Annual Report on Form 20-F*, p. 19.
[e] "3,000 Jobs Face Axe in $5bn BP-Mobil Deal," *The Independent (London)* (March 1, 1996), p. 1.

Asia-Pacific and Unconsolidated Operations

In the 1990's, income from unconsolidated affiliates ranged from 20 to 50 percent of bottom-line net income from foreign downstream operations. However, in 1997 this trend reversed. Equity income from unconsolidated affiliates fell for the first time since 1992 (Figure 10), by 3 percent. In fact, excluding Mobil, which added substantially to its equity income through the first year of operation under its merged European downstream operations with BP (see the Highlight entitled "BP-Mobil Alliance of European Refining Operations"), equity income was down 27 percent.

Figure 10. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates for FRS Companies, 1990-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Gross margins for the Pacific Rim (represented by Singapore/Dubai refining margins) fell in the first half of 1997 and continued to deteriorate in the latter half of the year compared to 1996. There were many underlying reasons that contributed to the drop in margins. Slower economic growth in the region, particularly in Japan, began in the second quarter. The GDP growth rate for Japan, the largest consumer of petroleum products in the region, was 0.8 percent in 1997 compared to a 4.1-percent growth rate in 1996. The decline was partly due to the hike in the sales tax imposed by the government in April (that heavily impacted consumption).[58] In addition, the currency devaluation in South East Asia that began in the third quarter was a major contributor to depressed margins in the latter half of the year. The FRS companies with operations in the region reported earnings were negatively impacted by currency devaluation in the region as they were unable to recover dollar denominated crude oil costs (see the Highlight entitled "The Asian Economic Crisis"). All the majors in the region reported a decline in earnings.

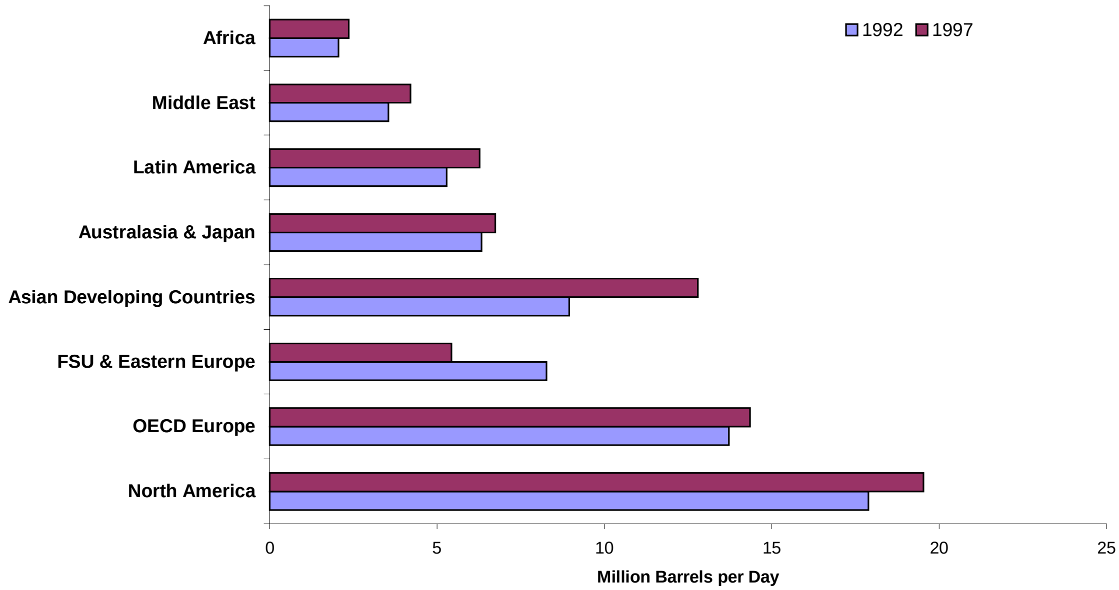
Caltex (the foreign downstream joint venture between Chevron and Texaco, and the largest foreign refining/marketing FRS unconsolidated affiliate), reported that "margins were adversely affected by currency devaluations in Thailand, Malaysia, and the Philippines",[59] and that operations in this region accounted for 84 percent of their earnings in 1997.[60]

HIGHLIGHT: The Asian Economic Crisis

During the last half of 1997, a currency crisis swept through several countries in Asia (in particular, in South East Asia). The financial turmoil began in Thailand when the government floated the country's currency, the baht, on July 2, 1997 resulting in its devaluation. A severe recession in Thailand followed the depreciation of the baht and had a rippling effect on other economies in the region. However, some countries fared differently than others. Thailand's currency fell more rapidly than other countries, at 50 percent. Currencies in Indonesia, Philippines and Malaysia depreciated 30 to 35 percent, while currencies of Korea, Singapore and Taiwan saw a decline of 10 to15 percent. China and India, also in South East Asia, were relatively immune to the crisis since their markets are not entirely open to the world.[a]

The crisis in the South East region has had a negative impact on regional economic activity as well as adverse spillovers to other countries in Asia. WEFA, an economic forecasting service, projected that economic recovery in the affected South East Asian countries will not occur until 1999, and that recovery will be delayed in Thailand until 2000.[b] Petroleum demand for the entire Asian region has important implications for world oil demand, since the Asian Developing Countries (ADC)[c] portion of that region has been the most rapidly growing area in the world (Figure 11). For example, petroleum demand in ADC increased at an annual average rate of 7 percent between 1992 and 1997, while demand growth for other regions in the world was significantly lower. For the Latin American[d] and the Middle East regions, the annual growth rate between 1992 and 1997 registered 3 percent in each region. In the North American[e] and European OECD[f] regions, average annual growth was 2 percent and 1 percent, respectively, and 1 percent in Australia[g] and Japan. In 1997, petroleum consumption by Asian countries increased 3 percent (notably China with the fastest growth rate in the region), representing 27 percent of the world's oil consumption.[h] However, the rate of growth in 1997 was somewhat lower than 1996 due to the recent economic downturn. Worldwide forecasted growth in oil consumption has been concentrated in the Asia-

Figure 11. Petroleum Consumption by Region, 1992 and 1997



Source: British Petroleum, *BP Statistical Review of World Energy June 1998*, p. 10.

Pacific region, but with many of the countries in this region experiencing an economic slowdown, forecasts have been revised down.

Impacts on Petroleum Refining

The FRS companies with refining operations in the region, particularly in Korea, Indonesia, Malaysia, and the Philippines, were negatively impacted by the devaluation of local currencies. The problem for refiners is that crude oil input prices are denominated in dollars, but sales of refined products outside the United States are in local currency.

Local refined product prices, when converted to U.S. dollars, will be lower after a local currency devaluation. Consequently, refiners will experience reduced dollar margins post-devaluation. The downward pressures on margins are exacerbated when the devaluation is followed by adverse economic impacts, as was the case for several countries in the Asia-Pacific region in the second half of 1997, with corresponding effects on petroleum product demand.

Despite the economic crisis in the region, the FRS companies with foreign downstream assets continue to view the region as a future growth area. Recently, however, they have implemented cost reduction programs and reduced refinery throughput in Asia to adjust to low petroleum demand and sluggish earnings.

Shell and Caltex initiated cost-cutting measures to survive the financial crisis in the region. In Thailand, the Rayong Refinery (owned by Royal Dutch/Shell, the parent company of the FRS company Shell Oil) stepped up cost-cutting efforts which they had been conducting jointly with a nearby refinery, Star Petroleum Refining (64-percent owned by Caltex, a 50-50 joint venture between Chevron and Texaco). These efforts included joint purchases of crude oil, feed stock swaps and shared gas export facilities. Prior to this collaboration effort, each refinery ran at 10 to 15 percent below capacity.[i] In addition, to further reduce costs at its Rayong Refinery, Royal Dutch/Shell set up a regional refinery operation in Singapore to coordinate its refinery operations in Singapore, Malaysia, Thailand, and the Philippines. However, all of these measures were not enough to remain competitive in the region. In April 1998, Caltex and Royal Dutch/Shell signed a Memorandum of Understanding to merge their Thai refinery operations into a single unit. The new refinery, expected to open by the end of 1998, will be the largest facility in Thailand with an operating capacity of 300,000 barrels per day. This joint venture will give Caltex and Royal Dutch/Shell greater buying power for crude oil. In addition, a new round of cost-reduction measures will be implemented at the facility.[j] In addition, Caltex reported that it is focusing on cost-reduction and recurring capital investment in the affected countries.[k] In response to depressed margins, Mobil began a restructuring program to focus on improving profitability at its Japanese and Australian marketing businesses.[l]

Other companies implemented reductions in output and capacity, also as a result of depressed refining margins. Refiners in Singapore reduced production due to increased competition from new refineries in Asia (particularly in South Korea, and Thailand), especially during this period when demand for petroleum products is low. Shell Eastern Petroleum (the largest refinery in Singapore) cut its workforce by 25 percent, and reduced refinery capacity at its Pulau Bukom refinery. Shell also announced a cost control program to improve efficiency, productivity and competitiveness during this time of low margins.[m] Indonesian refiners stopped the importation of crude oil and refined products and diverted most of their oil exports to local refineries.[n]

Upstream Impacts

Much of the exploration and development activity by the FRS companies in the Asia-pacific region is tied to expectations of strong growth in demand for natural gas in the region. Over the period 1987 through 1996, the Asia-Pacific region was the industry's "star" region in terms of demand growth. Consumption of natural gas in the region increased by an average annual rate of 7.1 percent (as compared to 1.9 percent in the rest of the world).

There are vast differences in costs of transporting oil versus natural gas. In general, oil is cheaper to transport (with costs being less than 10 percent of the wellhead price) while the cost of transporting gas can be more than 100 percent of the wellhead price, depending on the distance and the mode of transport. As a result of these differences, much of the increased demand for oil in Asia over the 1987 to 1996 period could be supplied by sources almost anywhere.

In contrast, the higher demand for natural gas required investments to increase indigenous production, piped gas, or LNG. In the case of Japan, Taiwan, and South Korea (which together accounted for almost 80 percent of worldwide trade in LNG in 1996), consumption increased by 6.9 percent annually over the 1987 to 1996 period. Almost all of this increase was satisfied by greater reliance on LNG imports.

Based on this trend, one leading analyst predicted that LNG trade would double or triple between the late 1990's and 2010.[o] Some even had the view that supply would be unable to keep up with the seemingly insatiable demand. For example, GasTrade 95, an international conference focusing on LNG trade, opened with a keynote address that asserted that "there will not be sufficient LNG available to meet even the lowest expectation of demand in the early years of the next century."[p]

Underlying the optimistic forecasts was the notion that because natural gas is an environmentally preferred fuel, the rate of growth in LNG demand could be expected to outpace the growth in demand for competing fuels. While this view is probably still valid, the economic crisis that swept through Asia beginning in July 1997 has demonstrated that the demand for natural gas is not immune to economic downturns. As evidence of this, imports of LNG by South Korea, the world's second largest importer, were almost 20 percent lower in the first half of 1998 as compared to the same period in 1997.[q]

As a result of the lingering economic downturn, corporate planners have had to sharply scale back their forecasts of future demand. In general, projects premised on LNG exports are tending to be postponed while those serving a more local market (where costly investments in transportation are less of a factor) are largely being reaffirmed. Some of the projects in question are:

Natuna. This project in Indonesia is expected to yield 46 trillion cubic feet (tcf) of gas reserves, more than the total level of proved gas reserves in the Federal waters of the Gulf of Mexico. Given the size of the field, the project can only be viable if the gas can be exported. Before the crisis, the partners in the project (Exxon, Mobil, and Pertamina, the Indonesian state oil company), planned on using the gas from the project to export 4.5-million metric tons per year of LNG starting in 2003 to 2004. It was also envisioned that gas from the project would also be sent to Thailand via a 1,612-kilometer (km) subsea pipeline. In late July, development of the project was suspended because of the economic downturn.[r]

Tangguh. This project is also located in Indonesia. Discovered by ARCO in 1995, with over 18 tcf in possible reserves, it rivals the giant Arun field operated by Mobil (also located in Indonesia) in terms of ultimate recovery and is the third largest discovery of hydrocarbons in ARCO's history. Like Natuna, development of the field will only be viable if the gas can be exported. Prior to the crisis, gas from the field was to be exported as LNG starting in 2003. As of this point, the fate of the project is far from clear although there are indications that it may be delayed.[s] While Tangguh's timing is in doubt, ARCO has recently reaffirmed its commitment to exploration and production in Asia by purchasing Union Texas, which has more than a third of its assets in Indonesia.[t]

Canago-Malampaya. This field is located in the offshore Philippines. It is expected to cost $2 billion to develop the field and construct a 504-km subsea pipeline from the field to the main island of Luzon. Royal Dutch Shell, the operator of the project, has recently reaffirmed its decision to develop the field by awarding Allseas Marine Contractors, S.A. a $500-million contract to install the pipeline.[u]

The Gulf of Thailand. Unocal's Pailin field was originally expected to commence production by the end of 1998. Startup has subsequently been delayed until September 1999. Indicative of its confidence in the region's long term prospects, ARCO has recently acquired a 25-percent interest in a 10-tcf project in the Malaysia-Thailand Joint Development Area.[v]

Australia. Before the crisis, there were plans to double production from the Northwest Project to 14.5 million tons of LNG per year by 2003. Given the current turmoil in the market, there are indications that the expansion may be delayed.[w] Development of the nearby Gorgon's project (a joint venture of Chevron, Texaco, Mobil, and Royal/Dutch Shell) is even more doubtful. Gorgon had been scheduled to be in production by 2003, but needs commitments from buyers. Development of the proposed Darwin project is also problematic. Given the current state of the market, some analysts are doubtful whether any new project will be started up in Australia before 2010.[x]

Alaska North Slope Gas Project. The crisis in Asia has possible ramifications on plans to develop the over 25 tcf of unexploited gas located on the North Slope of Alaska. Prior to the crisis, consideration was being given to developing the gas for export to Asia. Under one version of the plan, gas would be transported from the North Slope in a gas pipeline parallel to the existing oil pipeline. At the terminal in Valdez, the gas would be liquefied and exported as LNG to markets in Asia. On August 11, 1998 ARCO announced an agreement with Phillips Petroleum, CSX, and two other firms to spend 100 million dollars over the next four years doing the necessary engineering and permitting work.[y] The overall cost of the project is in the range of $12 to $15 billion with cost per million Btu in excess of $4.00. British Petroleum and Exxon (the two other major owners of the gas) have declined to participate in the assessment, having concluded that the project is not economic unless costs can be substantially reduced.[z]

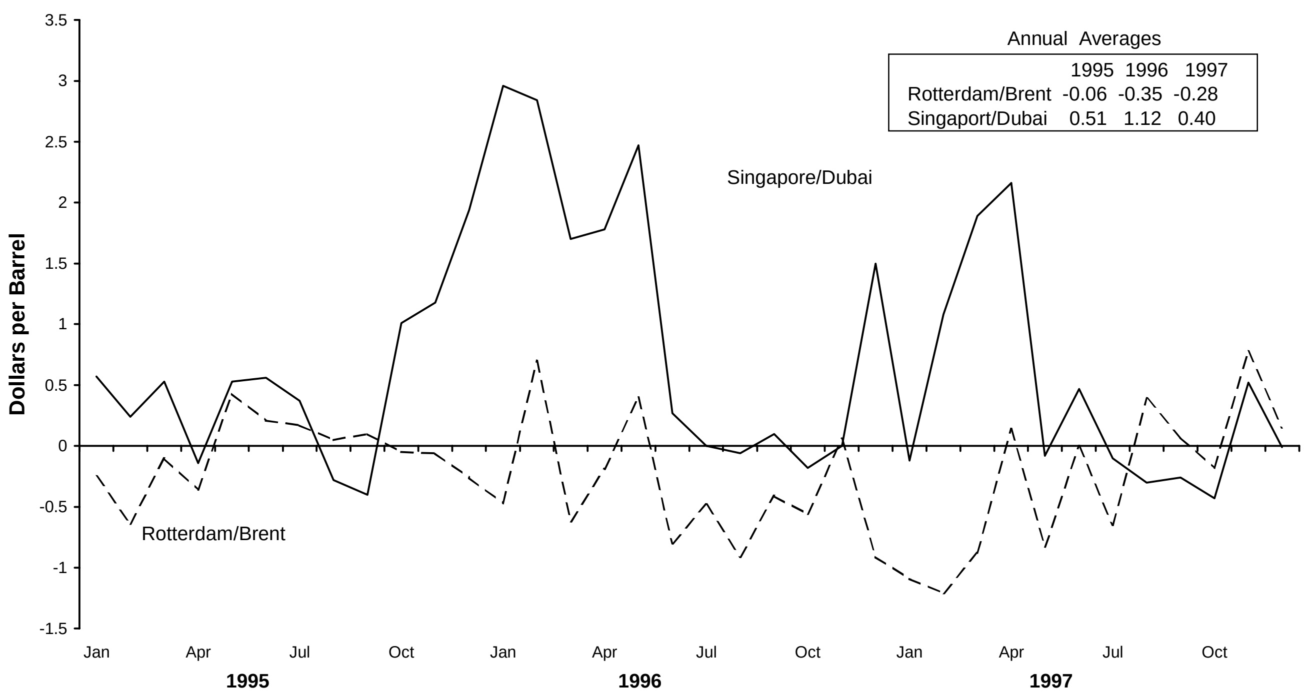
[a]"Developing Asia: Tigers Take Time-Out," *WEFA World Economic Outlook: Developing Economics Pre-Meeting Forecast, Volume 1A (*November 1997), p. 1.21, and "East Asia: The Energy Situation," Energy Information Administration, *Country Analysis Brief* (July 1998), http://www.eia.doe.gov/emeu/cabs/eastasia.html.
[b]"Developing Asia: Tigers Take Time-Out," *WEFA World Economic Outlook: Developing Economics Pre-Meeting Forecast, Volume 1A (*November 1997), p. 1.23.
[c]Asian Developing Countries include Bangladesh, China, and China SAR (Special Administrative Region of Hong Kong), India, Indonesia, Malaysia, Pakistan, Philippines, Singapore, South Korea, Taiwan, Thailand, and Other Asia Pacific.
[d] Mexico is included in the region "Latin America," and not in the region of "North America."
[e] North America includes Canada and the United States in this instance. Mexico is included in the category, "Latin America."
[f] Asian Developing Countries include Bangladesh, China, China SAR (Special Administrative Region of Hong Kong), India, Indonesia, Malaysia, Pakistan, Philippines, Singapore, South Korea, Taiwan Thailand, and Other Asia Pacific.
[g] Australasia includes Australia and New Zealand.
[h]British Petroleum Corporation, *1997 BP Statistical Review of World Energy,* p. 10.
[i]"Shell Boost Cooperations with Caltex,"*The Nation (Bangkok) (* October 30, 1997).
[j]"Rayong and Star Refineries Merge," *Petroleum Economist (* April 23, 1998, p. 57).
[k]"Texaco Corporation, *1997 Securities and Exchange Commission 10-K Form*, p. 2.
[l]"Mobil Announces Record 1997 Operating Earnings of $3,430 Million", *Mobil Corporation, News Release for the Financial Community* (January 28, 1998), p. 2.
[m]"Shell Boost Cooperations with Caltex, "*The Nation (Bangkok) (*October 30, 1997).
[n]*Oil and Gas Journal* (March 9, 1998), p. 4.
[o]The LNG Observer, "Cedigas Forecasts World LNG Trade Could Double or Triple by 2010" (January-February 1997).
[p]The LNG Observer (Spring 1995).
[q]International Gas Report (June 1998).
[r]Platt's Oilgram News (August 4, 1998).
[s]Platt's Oilgram News (August 4, 1998).

[t]ARCO, http://www.arco.com/corporate/news/p051298b.htm (December 19, 1998).
[u]Hart's Daily Petroleum Monitor, "Allseas Wins Malampaya Deal" (August 17, 1998).
[v]ARCO, http://www.arco.com/corporate/news/p080398.htm (December 19, 1998).
[w]Petroleum Economist, "The Problems Multiply in Asia" (September 22, 1998, p. 78).
[x]The LNG Observer (October 1998).
[y]ARCO, http://www.arco.com/corporate/news/a081198.htm (December 19, 1998).
[z]Platt's Oilgram News, "BP Seeks to Cut Cost of LNG Project" (August 3, 1998).

Europe and Consolidated Operations

In the 1990's, foreign refining and marketing income from consolidated operations has ranged from 50 to 80 percent of bottom-line net income. In 1997, net income from consolidated operations reversed its general decline of the 1990's and more than doubled to a level not seen since the war-induced profit run ups of 1991 (Figure 10). Gross margins in Europe (represented by Rotterdam/Brent refining margins) were falling in the first half of the year, but reversed direction in the latter half of the year as a result of increased economic growth in Europe which increased demand for petroleum products (Figures 11 and 12). All the FRS companies with foreign refining assets reported gains from their European operations and spoke of improved "refining and marketing margins" as the reason. Exxon reported "refining margins in Europe strengthened and marketing margins benefited from an improved United Kingdom retail environment."[61] Other majors spoke of similar reasons for their increase in earnings.[62] The generally favorable European conditions were reflected in the 152-percent growth in income from consolidated foreign refining/marketing operations (Table 10).

Figure 12. Foreign Refining Margins, 1995-1997



Note: Refining margin is defined as netback crude oil price less spot crude oil price. Netback price is calculated by multiplying the spot price of each refined product by the percentage share in the yield of a barrel of crude oil. Transport and out-of-pocket refining costs are then subtracted to arrive at netback price.
Sources: **1997**: *Oil Market Intelligence* (January 1998 and July 1997), p. 12; **1996**: *Petroleum Market Intelligence*, Vol. 8, No. 12 (January 4, 1997), p. 8; and **1995**: *Petroleum Market Intelligence*, Vol. 7, No. 12 (January 5, 1996), p. 8.

U.S. Refining and Marketing

The profitability of U.S. refining and marketing during 1997 was the highest since 1989, when the return on investment from these operations last exceeded 10 percent (Figure 9). The reasons for this peak in 1990's profitability are partially due to events of 1997 and partially due to developments over the last several years. (Downstream mergers, as well as the formation of a number of downstream alliances and joint ventures, also underlie the current profitability in downstream operations. For a more extensive discussion of these developments, see the Highlight entitled "Cost-Cutting Through Combination.")

HIGHLIGHT: Cost-Cutting Through Combination

Joint ventures are one of the mechanisms that FRS companies have used to consolidate their downstream[a] petroleum operations. Such deals may provide these companies with a way of reducing their costs by sharing assets and operations without some of the problems of a full-scale merger of the two companies involved. These deals may also increase the value of the fixed assets involved since many of the joint ventures are carried as unconsolidated affiliates by their corporate parents (who benefit from the combination of the assets by receiving a share of the revenues). (In addition to forming downstream joint ventures and alliances in the United States, some FRS companies are also forming these alliances abroad. See the Highlight entitled "BP-Mobil Alliance of European Refining Operations" in Chapter 3 for a discussion of one of the most significant of the foreign alliances.)

The largest of recent domestic joint ventures combines the U.S. refining and marketing assets of Texaco, Star Enterprise (a joint venture between Texaco and Aramco, the Saudi Arabian state oil company), and Shell Oil (the U.S. subsidiary of Royal Dutch/Shell). The joint venture was announced in late 1996 and resulted in the creation of two companies, Equilon Enterprises L.L.C. and Motiva Enterprises L.L.C. (in January and May, 1998, respectively). Equilon consists of the companies' western and midwestern U.S. operations as well as their nationwide trading, transportation, and lubricants businesses.[b] Part of the consent agreement with the U.S. Federal Trade Commission reduced Equilon's assets.[c] In particular Texaco agreed to sell 60 retail outlets in southern California and Hawaii[d] and Shell Oil agreed to sell its Anacortes, Washington refinery (108,200 barrels per day (b/d) capacity).[e] Motiva consists of the companies' eastern and Gulf Coast U.S. operations (with the exception of Shell's Deer Park, Texas refinery, which also is operated as a joint venture between Shell Oil and the state oil company of Mexico, Petroleos Mexicanos).

The resulting ventures will have combined assets with a book value of approximately $10 billion. Equilon will have 7 refineries with a total crude oil distillation capacity of approximately 846,000 b/d and slightly more than 9,000 retail outlets in 32 states. Motiva will have 4 refineries with a total crude oil distillation capacity of 819,000 b/d and almost 14,000 retail outlets in 27 states.[f] The Texaco-Star-Shell alliance is anticipated to reduce the aggregate operating costs of the companies by $800 million annually.[g]

As of January 1, 1998, USX-Marathon Group, a subsidiary of the USX Corporation, and Ashland Oil, an affiliate of Ashland Inc., merged their downstream assets into a joint venture (called Marathon Ashland Petroleum L.L.C.). USX-Marathon Group is operating the joint venture and is the majority partner with a controlling interest of 62 percent.[h] The venture has a combined refining capacity of 924,300 b/d[i] and more than 3,000 retail outlets.[j] The joint venture is anticipated to result in savings of $200 million annually in operating costs.

Other joint ventures are more limited in their scope, involving a single refinery with each partner having a 50-percent share of the venture. As with the larger ventures, they too are aimed at reducing costs either through reducing or eliminating redundancies, reducing logistical costs, or reducing unused capacity.
Amerada Hess and Petroleos de Venezuela, S.A. (PdVSA), the state oil company of Venezuela, also formed a refinery joint venture in 1998. Hess provided its St. Croix, Virgin Islands 495,000 b/d refinery,[k] receiving $62.5 million in cash and a 10-year note in the amount of $562.5 million. A delayed coking unit will be constructed at the refinery. The resulting joint venture company, Hovensa LLC, signed a long-term supply contract with PdVSA under which it will receive 155,000 b/d of Venezuelan crude with another 115,000 b/d of heavy Venezuelan crude after the delayed coking unit is completed.[l]

Mobil and Citgo (the U.S. wholly-owned affiliate of PdVSA) formed a joint venture during 1997 to operate Mobil's Chalmette, Louisiana refinery beginning in 1998. Mobil contributed the 159,000 b/d refinery[m] and PdVSA will contribute at least part of the crude oil processed at the refinery.[n]

Along the same lines, Phillips Petroleum and PdVSA agreed during 1997 to a refinery joint venture involving Phillips' 200,000 b/d Sweeny, Texas refinery.[o] Phillips contributed the refinery and PdVSA will contribute as much as 165,000 b/d of heavy Venezuelan crude oil. A new $450-million, 58,000 b/d coking unit will be constructed at the refinery starting in late 1998 to facilitate the processing of heavy crude oil.[p]

Subsequently, the non-FRS company Ultramar Diamond Shamrock (UDS), which acquired Total Petroleum North America in 1997, including 3 refineries and more than 2,100 marketing outlets, announced a joint venture with Phillips in October 1998.[q] The venture will combine Phillips' refining and marketing operations with UDS. The venture will be called Diamond 66 LLC and controlled by UDS (55 percent share), with Phillips focusing on its upstream petroleum business.[r] This effort represented Phillips' second attempt to form a downstream joint venture. In 1996, Phillips' attempt to form a downstream joint venture with DuPont/Conoco was thwarted, as the companies were unable to agree on the value of the assets each would contribute to the venture.[s]

[a]Downstream petroleum refers to petroleum refining, marketing, and transportation. However, transportation (chiefly pipelines and marine transport) is omitted from this discussion.
[b]Shell Oil owns 56 percent of Equilon and Texaco has a 44-percent share. See "Shell, Texaco and Saudi Refining Inc. Announce Approval of Eastern/Gulf U.S. Downstream Alliance: Motiva Enterprises," Business Wire (May 2, 1998).
[c] Shell Oil, *1997 Annual Report*, p. 52 and Texaco, *1997 Annual Report*, p. 20.
[d] "Shell/Texaco Seeking Buyer of 60 U.S. Gas Stations," Reuters World News Service (July 7, 1998).
[e] Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 40.
[f] "Shell, Texaco, and Saudi Aramco Announce Formation and Operational Start-Up of Motiva

Enterprises," Business Wire (July 2, 1998).
[g]Hillary Durgin, "Marketing, Refining Pact Signed; Texaco, Aramco, Shell Teaming up," *The Houston Chronicle* (May 28, 1998), p. 1.
[h]"Ashland, Marathon Ink Merger Agreement After FTC Clears Deal," *Octane Week*, Volume 12, Number 49 (December 15, 1997).
[i] Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 40.
[j] *National Petroleum News*, *Market Facts 1998* (mid-July 1998), p. 47.
[k] Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 38.
[l] "Amerada Hess Announces Establishment of Refinery Joint Venture with Petroleos de Venezuela," PR Newswire (November 2, 1998).
[m]Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 40.
[n]Mobil Corporation, *1997 Annual Report*, p. 42.
[o] "Phillips, Corpoven Sign Principles of Agreement To Build New Coker," Phillips Petroleum News Release (August 22, 1997). See also http://www.phillips66.com/newsroom/rel122.html (November 19, 1998).
[p] "Phillips, PdVSA Agree to Build Coker At Phillips' Sweeny, Texas, Complex," Phillips Petroleum News Release (November 2, 1998). See also http://www.phillips66.com/newsroom/rel197.html (November 19, 1998).
[q] "Ultramar Diamond Shamrock and Phillips Petroleum to Form Joint Venture Creating Largest Independent Refining and Marketing Company in North America." Phillips Petroleum News Release (October 8, 1998). See also http://www.phillips66.com/newsroom/rel191.html (November 19, 1998).
[r]"Phillips Unloads Refining Headache with Venture," *Dow Jones Newswires* (October 8, 1998).
[s] "Conoco CEO Sees Company Going It Alone In U.S. Downstream," Dow Jones News Service (November 10, 1997).

While Revenues Fall, Costs Fall Faster and Profits Rise

The profitability of the FRS companies' refining/marketing operations can be analyzed by examining the net margin. The net margin is the difference between petroleum product revenues and all out-of-pocket refining and marketing expenses per barrel of refined products sold.[63]

The average price received by the FRS companies for refined petroleum products fell by 4 percent between 1996 and 1997. Motor gasoline prices registered a slight 1-percent decline, with most of the overall price decline attributable to other products (Table 12). This pattern of price change reflected the relatively greater growth in demand for transport fuels, due to generally strong economic growth, and a drop in demand for heating fuels, due to mild winter weather in 1997.[64]

Consumption of petroleum products in the United States increased by 2 percent during 1997.[65] However, sales of petroleum products by the FRS companies declined 5 percent over the same period (Table 12). The decline was due to the exit of two companies, Unocal and Sun, from FRS petroleum refining and marketing operations at the end of 1996. (Unocal exited from downstream petroleum operations, but remains an FRS respondent company. Sun Company continues to operate in downstream petroleum operations, but was not an FRS respondent company during 1997.) Although aggregate domestic petroleum product sales by the FRS companies declined between 1996 and 1997, aggregate sales by those FRS companies with continuing U.S. refining and marketing operations (those other than Unocal and Sun)[66] increased by more than 3 percent. Thus, although the total FRS share of domestic petroleum product sales declined between 1996 and 1997, the share held by continuing refiners and marketers increased slightly.

Table 12. Sales, Prices, and Margins in U.S. Refining/Marketing for FRS Companies, 1996-1997

Sales, Expenses, and Income	1996	1997	Percent Change 1996-1997
	(million barrels per day)		
Refined Product Sales	14.02	13.29	-5.2
Average Sales Price	(dollars per barrel)		
Gasoline	30.27	30.02	-0.8
Distillate	26.65	25.10	-5.8
Other	23.00	20.79	-9.6
All Refined Products	27.65	26.61	-3.8
Raw Material Input and Product Purchases per Barrel	21.16	19.83	-6.3
Average Sales Price Less Cost of Raw Materials and Product Purchases (Gross Margin)	6.49	6.78	4.5
Direct Operating Costs	5.62	5.31	-5.5
Refined Product Margin [a]	0.87	1.47	68.5
Gasoline Marketing Margins			
Wholesaler/Reseller	5.09	5.65	10.9
Retailer	2.19	1.99	-8.8

[a] See Appendix B, Table B48, for the components to calculate the refined product margin.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

In aggregate, the FRS companies more than survived the reduction in their revenues as their costs of raw materials (chiefly crude oil costs) and product purchases fell by more than did overall refined product prices. As a result, gross margins (refined product revenues less raw material and product purchases divided by refined product sales volume) were substantially higher in 1997 than in 1996 and were the highest since 1992 (Figure 13).

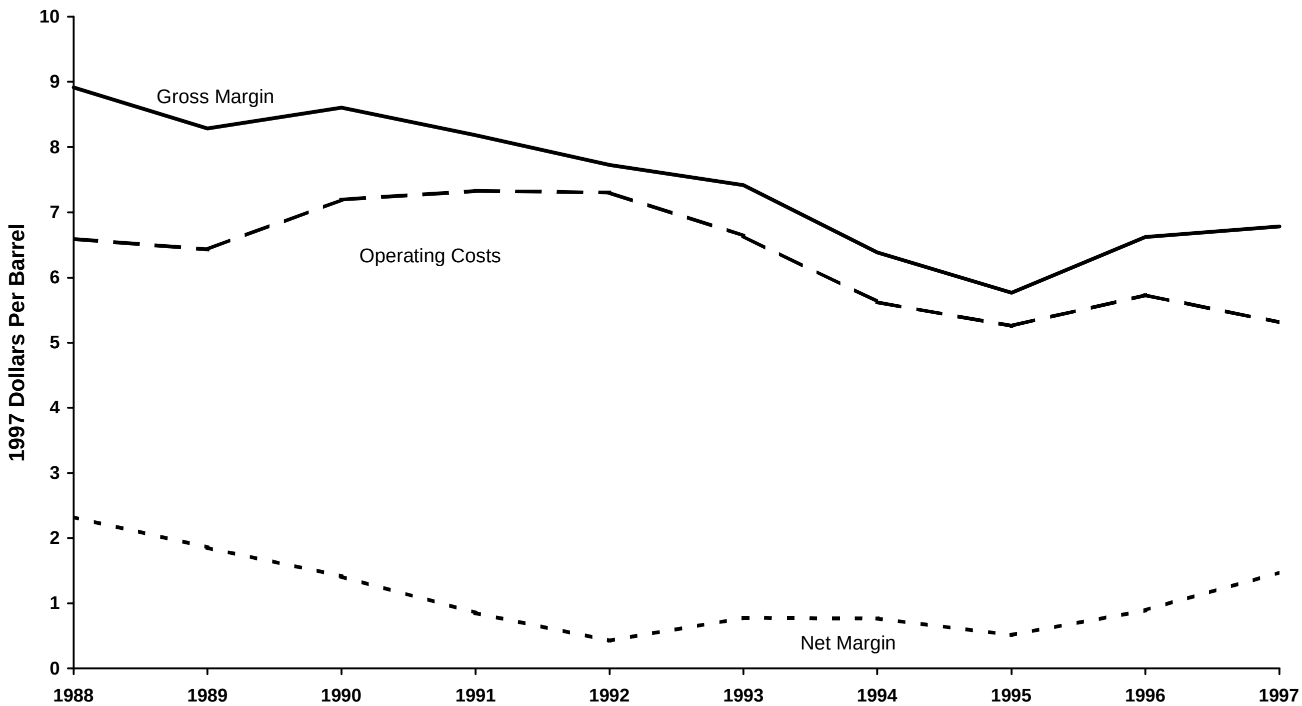
Although gross margins were at their highest level since 1992, the primary reason that net refined product margins were so high during 1997 was that operating costs were reduced by 6 percent between 1996 and 1997. The FRS companies' reduction in operating costs in 1997 was part of a longer-term trend. All categories of operating costs have been reduced since 1990, a stated goal of the FRS companies for several years including 1997.[67]

Marketing costs were reduced by 28 percent between 1990 and 1997 and by 5 percent during 1997 (Table 13). The reduction in marketing costs is partially due to many of the FRS companies divesting themselves of their credit card operations and undertaking other cost reduction efforts during the 1990's.[68] Additionally, the FRS companies reduced the number of their branded outlets by 34 percent over the same period of time, becoming more regional in their approach to marketing, a move which led to reduced expenses.

The FRS refiners reduced energy costs by 24 percent between 1990 and 1997 and by almost 6 percent between 1996 and 1997. Many of the FRS companies are utilizing cogeneration to provide at least some of their electricity needs.[69] Thus, although the gross refined product margin fell by 21 percent between 1990 and 1997, the net refined product margin increased by almost 1 percent over the same period because of the substantial reduction in costs (Table 13).[70]

In total, the FRS companies' refined product margin increased by almost 70 percent between 1996 and 1997 (Table 14). Although the refined product margin increased for all groups of FRS companies (ranked by the size of total energy assets), the largest FRS companies led the three groups with an increase of 108 percent. The group of smallest companies closely followed the group of largest companies with an increase of 76 percent. Trailing was the group of mid-sized companies, which had an increase of 33 percent.

Figure 13. FRS U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold, 1988-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 13. FRS U.S. Refined Product Margins and Costs per Barrel Sold, 1988-1997
(1997 Dollars per Barrel)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Gross Margin [a]	8.91	8.29	8.60	8.18	7.73	7.42	6.38	5.77	6.62	6.78
less										
Marketing Costs	2.05	2.28	2.45	2.78	3.03	2.38	1.92	1.82	1.86	1.76
Energy Costs	1.39	1.33	1.36	1.35	1.26	1.28	1.02	0.86	1.09	1.03
Other Operating Expense	3.16	2.83	3.39	3.20	3.01	2.97	2.68	2.57	2.78	2.52
equals										
FRS Refined Product Margin [b]	2.32	1.85	1.41	0.85	0.42	0.78	0.76	0.51	0.89	1.47
Refined Product Sales	14,114	13,486	13,222	13,015	13,089	13,178	13,455	13,641	14,024	13,294

[a] Refined product revenues less raw material and product purchases divided by refined product sales volume.
[b] Calculated from unrounded data.
Mb/d = Thousand barrels per day.
Source: Energy Information Administration Form EIA-28 (Financial Reporting System).

Table 14. Marketing Characteristics and Refined Product Margin for FRS Companies Ranked by Total Energy Assets, 1996-1997

Group	Average Outlet Volume (thousand gallons per month)		Refined Product Margin Per Barrel (dollars per barrel)		Marketing Expenses Per Barrel (dollars per barrel)	
	1996	1997	1996	1997	1996	1997
Top Four	81.07	97.21	0.83	1.73	1.91	1.89
Five Through Twelve	122.36	121.04	1.02	1.35	2.18	1.79
All Other	59.44	55.33	0.72	1.27	1.19	1.43
All FRS	88.78	98.49	0.87	1.47	1.82	1.76

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Sophisticated Refiners Able to Buy Low, Sell High

Starting in the late 1970's and continuing to the present, the FRS companies have invested heavily in their refineries in order to utilize heavier, more sulfurous crude oils as inputs. Over the same period, the FRS companies have invested in upgrading their refineries to produce greater proportions of lighter, higher valued products, particularly motor gasoline (Table 15). The actual returns to these investments depend not only on the levels of input and product prices, but also can be strongly affected by the differences in prices of light and heavy petroleum products and high and low quality crude oils.

Table 15. U.S. Refinery Configurations of FRS Companies, Selected Years, 1974-1997

Process	1974	1981	1997
	Downstream capacity as a percent of crude distillation		
Coking	n.a.	n.a.	12.6
Catalytic Cracking	27.70	30.40	35.9
Catalytic Reforming	17.60	22.40	23.4
Hydro Cracking	5.60	5.70	9.6
Alkylation	4.80	5.30	7.5

n.a.: Information not available.
Sources: *Oil and Gas Journal*, "Worldwide Refinery Report," 1974, 1981, and 1997.

A refinery with a large capital investment directed toward processing lower quality crude oils will do better financially than less versatile refineries when the difference in price between high quality crude oils and low quality crude oils is large. Similarly, a refinery that has been upgraded to produce a larger yield of light products will do better than a less sophisticated refinery when the difference between lighter products (e.g., motor gasoline) and heavier products (e.g., residual fuel oil) is large.

Part of the reason for the uptick in profitability in 1997 appears grounded in the refinery upgrades that the FRS companies have made. The upgrades have increasingly enabled the FRS companies to process relatively lower quality crude oil. In 1996 and 1997 the spread between high quality and low quality crude oil increased, reversing a prior five-year trend (Figure 14), a move that generally favored the typically upgraded FRS refinery.

The refinery upgrades also resulted in higher production of relatively more valuable light products through the addition of downstream processing units such as catalytic cracking and catalytic reforming units.[71] The FRS companies also have benefited in recent years from the increased complexity of their refineries by producing relatively more light products. The difference between the selling price for light products and the selling price for heavier products[72] has increased over the past few years after narrowing during the early 1990's (Figure 15).[73]

Figure 14. Real Price Difference Between Light Crude Oil and Heavy Crude Oil, 1978-1997

Note: Light crude oil is defined here as having an API gravity of 40.1 or greater and heavy crude oil is defined as having an API gravity of 20 or less.
Source: Energy Information Administration, *Petroleum Marketing Monthly June 1998*, DOE/EIA-0380(98/06), Tables 27 and 28.

Figure 15. Real Price Difference Between Motor Gasoline and Residual Fuel Oil, 1978-1997

Source: Energy Information Administration, *Petroleum Marketing Monthly,* DOE/EIA-0380(98/06) (Washington, DC, June 1998), Tables 4 and 5.

The movement in quality price spreads in 1995-1997 has favored upgraded refineries and was a development contributing to the recent upswing in the profitability of the FRS companies' U.S. refining/marketing operations.

Oil and Gas Production

Recent High Rates of Return Maintained

Net income from the FRS companies' worldwide upstream oil and gas operations totaled $20.2 billion in 1997, excluding unusual items,[74] 1 percent above the prior year's level (Table 16). The return on investment in U.S. and foreign oil production, at 12.9 percent and 11.9 percent, respectively, were second only to 1996 rates of return in the post-1986 period (Figure 4 in Chapter 2). The FRS companies maintained their strong upstream financial performance although oil prices were lower throughout most of 1997 compared to 1996. In both U.S. and foreign operations, offsets to lower oil prices included increased natural gas production, higher natural gas prices (Table 17), and modest cost cutting. However, the two areas displayed some contrasts in financial performance in 1997.

The FRS companies' overall U.S. revenues were flat from 1996 to 1997, as lower oil revenues were offset by increased natural gas revenues (Table 16). Lower oil revenues reflected a decline in average wellhead prices realized by the FRS companies and a drop in their U.S. oil sales and production (Table 17). About 80 percent of the decline in sales and production can be attributed to the formation of the Aera joint venture by Mobil and Shell Oil. These two FRS companies contributed their California producing properties and associated assets to the joint venture. The joint venture is treated as an investment for financial reporting purposes, rather than included in revenues and costs. The change in reporting had no effect on bottom-line income (as the income from Aera is now included in the income from unconsolidated affiliates), but did have the effect of reducing reported revenues and costs.

A 1-percent increase in the FRS companies' natural gas sales and production, in combination with a 9-percent rise in natural gas prices (Table 17) provided a boost in revenues sufficient to offset the decline in oil revenues. The data in Table 17 indicate that natural gas resales (measured by sales minus production) accounted for about one-third of the FRS companies' total natural gas sales volume in 1997. Deregulation of the natural gas industry, which began in the mid-1980's, encouraged the growth of resale and marketing activity, as interstate natural gas transmission companies were compelled to unbundle their transportation function from other revenue-generating activities. Prior to the onset of natural gas deregulation, resales were only 7 percent of FRS companies' total natural gas sales. By 1992, the last year before the full deregulation of U.S. natural gas prices, the resale share had increased steadily to 19 percent and reached the present level of 33 percent in 1995. Currently, at least half of the FRS companies are engaged in some form of natural gas resale and marketing activity.

On the cost side of U.S. oil and gas production, a slight increase in overall U.S. operating costs was offset by gains on sales of producing properties and an increase in income from unconsolidated affiliates. This latter development in part reflects the creation of upstream joint ventures, such as Aera, in 1997.

The FRS companies' foreign upstream operations were also adversely affected by lower oil prices in 1997. Although the FRS companies were able to increase their foreign oil production by 2 percent (Table 17), stepped-up production could not compensate for the $2-per-barrel drop in the average oil

Table 16. Income Components and Financial Ratios in Oil and Gas Production for FRS Companies, 1996-1997
(Billion Dollars)

Components of Income and Financial Ratios	United States		Foreign	
	1996	1997	1996	1997
Oil and Gas Revenues				
Oil	32.9	30.6	NA	NA
Gas	26.8	29.5	NA	NA
Total Revenues	59.8	60.1	47.8	44.2
Expenses				
DD&A	10.5	10.4	7.2	8.0
Lifting Costs	12.3	12.0	9.9	9.8
Exploration Expenses	1.6	2.1	3.2	2.9
General and Administrative Expenses	1.2	0.9	0.8	0.7
Raw Material Purchases	15.9	14.9	8.8	6.9
Other Costs (Revenues)	2.0	4.5	0.6	0.2
Total Operating Expenses	43.4	44.8	30.6	28.5
Operating Income	16.4	15.2	17.2	15.8
Other Income (Expense)[a]	0.9	1.9	2.3	2.3
Income Tax Expense	5.5	5.2	10.2	8.9
Net Income	11.8	11.9	9.2	9.1
Less Unusual Items	0.3	0.1	0.8	0.7
Net Income, Excluding Unusual Items	11.5	11.8	8.4	8.4
Unit Values (Dollars Per Barrel of Production COE)[b]				
Direct Lifting Costs (Excluding Taxes)	3.42	3.42	3.43	3.36
Production Taxes	0.70	0.67	0.92	0.83
Ratios (Percent)				
Return on Investment[c]	14.1	12.9	12.8	11.9
Effective Tax Rate[d]	31.7	30.4	52.7	49.6

[a]Earnings of unconsolidated affiliates and gain (loss) on disposition of assets.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of oil per thousand cubic feet.
[c]Net Income divided by net investment in place (Net investment in place = net property, plant, and equipment plus investments and advances).
[d]Income tax expense divided by pretax income.
NA = Not available.
-- = Not meaningful (less than $50 million).
DD&A = Depreciation, depletion, and amortization costs.
Note: Sum of components may not equal total due to independent rounding. Independent producers are publicly traded companies with oil and/or natural gas production whose primary industry code is Standard Industrial Classification 13 (oil and gas production and services).
Source: FRS Companies: Energy Information Administration, Form EIA-28 (Financial Reporting System).

price realized abroad. As a result, revenues from foreign oil production were down $2.1 billion between 1996 and 1997. The effects of this decline were moderated by a 4-percent increase in foreign natural gas production and slightly higher overall natural gas prices abroad. The largest absolute increase in natural gas production was in the Other Eastern Hemisphere region, up 11 percent, largely from Indonesia, Malaysia, Myanmar, and Thailand, followed by a 19-percent rise in South American natural gas production. Modest reductions in lifting costs, exploration expenses, and overhead expenses also served to partly offset the effects of lower oil prices. The decline in lifting costs was a continuation of a trend evident in the 1990's (Figure 16).

Table 17. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1996-1997

Prices, Sales, and Production	1996	1997	Percent Change 1996-1997
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,532.4	1,458.5	-4.8
Dry Natural Gas (Billion Cubic Feet)	8,191.6	8,298.5	1.3
Total (Million Barrels, COE)[b]	2,990.5	2,935.6	-1.8
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,933.2	1,862.5	-3.7
Dry Natural Gas (Billion Cubic Feet)	12,281.1	12,420.3	1.1
Total (Million Barrels, COE)[b]	4,119.3	4,073.4	-1.1
Domestic Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	17.04	16.43	-3.6
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.19	2.37	8.5
Composite (Dollars Per Barrel COE)[b]	14.51	14.75	1.6
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,438.7	1,473.9	2.4
Dry Natural Gas (Billion Cubic Feet)	4,678.4	4,859.0	3.9
Total (Million Barrels COE)[b]	2,271.5	2,338.8	3.0
Foreign Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	19.93	18.01	-9.6
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.19	2.22	1.4
Canada	1.25	1.54	23.2
OECD Europe	2.71	2.89	6.6
Other Foreign	2.03	1.88	-7.4
Composite (Dollars Per Barrel COE)[b]	17.13	15.96	-6.8

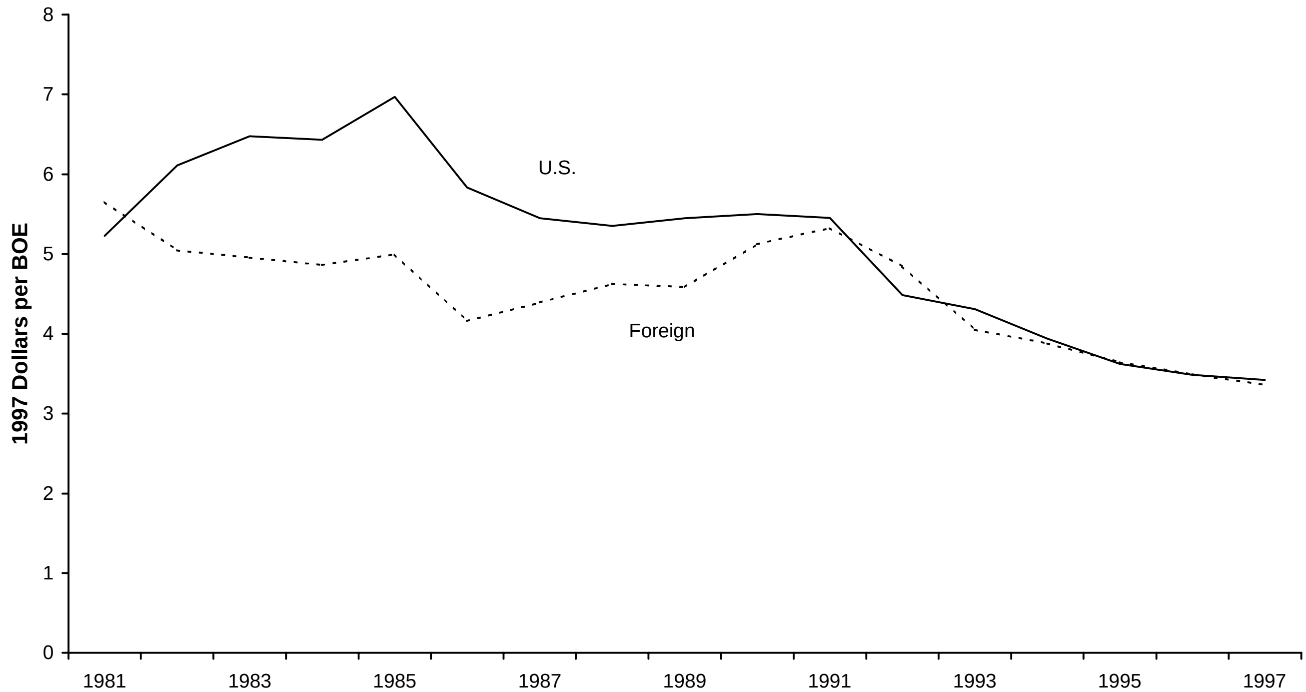
[a]Production is on a net ownership basis. Sales are domestic production segment sales. See Appendix A for discussion of FRS reporting conventions.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per thousand cubic feet.
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System). Foreign production segment per unit sales values were compiled from information in FRS companies' filings of Securities and Exchange Commission Form 10-K, annual reports to shareholders, and supplements to annual reports.

Lifting Costs and Fiscal Bite Continue on Downward Trends

Lifting costs are the costs of extracting oil and gas, including production taxes levied on wellhead revenues. They represent the largest cost component in upstream operations. Through cost-cutting, consolidation of producing properties, and application of new technologies (such as horizontal drilling) during the 1990's, the FRS companies have managed to reduce direct lifting costs per barrel (direct lifting costs exclude production taxes), adjusted for inflation, by nearly 40 percent (Figure 16). In the United States, direct lifting costs were essentially unchanged between 1996 and 1997; however, all foreign regions except South America registered lower costs in 1997 (Table 18). The increase in lifting costs in South America appears to be related to start-up costs in recently-formed joint ventures in Venezuela. In the 1995-1997 period, several FRS companies formed joint ventures with Petroleos de Venezuela, Venezuela's state energy company.[75]

Although lower lifting costs partly offset the effects of lower oil prices in 1997, a more significant contribution to bottom-line net income in foreign oil and gas production was a reduced level of income tax expense, down $1.3 billion from 1996 to 1997 (Table 16). About $0.7 billion of the reduction was attributable to lower taxable income. In addition, tax refunds from tax settlements reduced income taxes by $0.3 billion, and the remaining $0.3 billion reflected generally lower tax rates overseas.

Figure 16. Direct Oil and Gas Lifting Costs per BOE for FRS Companies, 1981-1997



BOE = Barrels of crude oil equivalent.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 18. Lifting Costs by Region, FRS Companies, 1996-1997
(Dollars Per Barrel of Oil Equivalent)

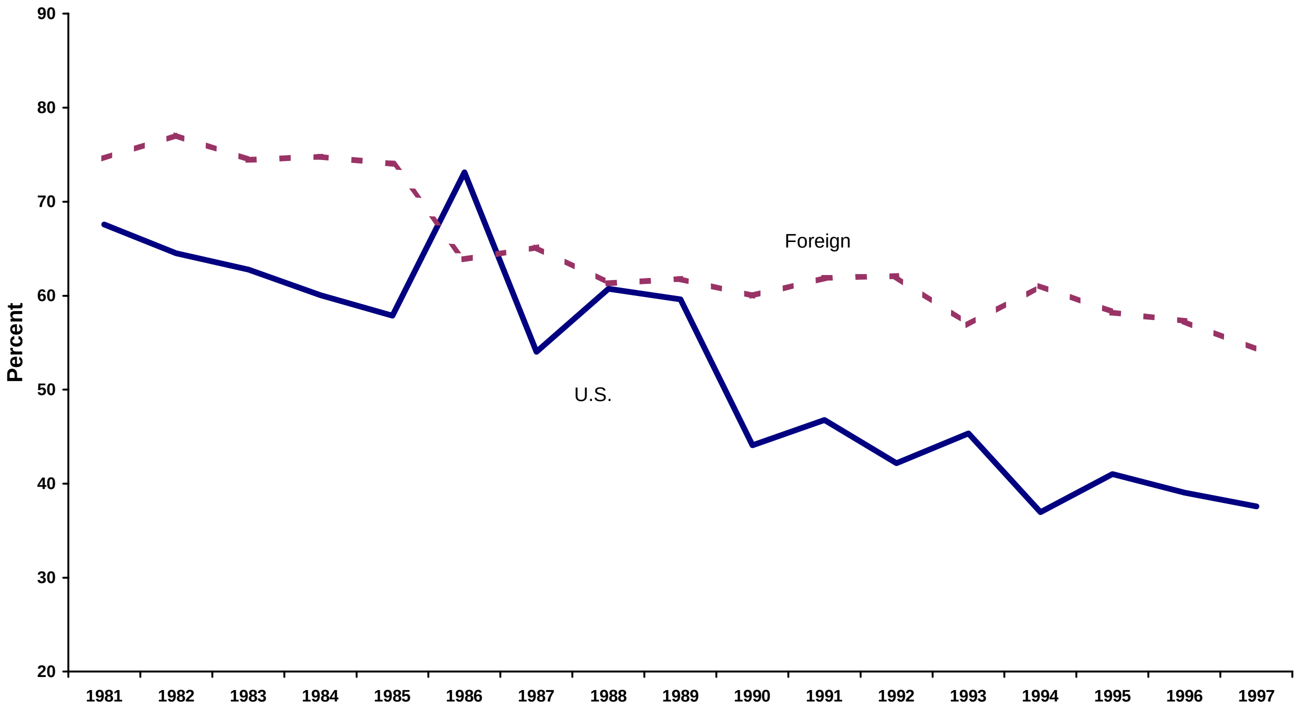
	Direct Lifting Costs			Production Taxes			Total		
Region	1996	1997	Percent Change	1996	1997	Percent Change	1996	1997	Percent Change
FRS Companies									
United States									
Onshore	--	--	--	--	--	--	4.57	4.60	0.7
Offshore	--	--	--	--	--	--	2.95	2.88	-2.4
Total United States	3.42	3.42	0.1	0.70	0.67	-4.6	4.12	4.09	-0.7
Foreign									
Canada	3.58	3.55	-0.9	0.32	0.33	1.2	3.91	3.88	-0.8
OECD Europe	4.40	4.35	-1.2	0.72	0.64	-11.4	5.12	4.99	-2.6
Africa	2.96	2.75	-6.9	1.63	1.44	-11.8	4.59	4.19	-8.7
Middle East	2.46	2.23	-9.6	1.56	1.68	7.8	4.02	3.90	-2.9
Other Eastern Hemisphere	2.15	2.01	-6.8	1.01	0.80	-20.5	3.16	2.81	-11.2
Other Western	2.71	3.31	22.4	1.25	1.10	-12.2	3.96	4.41	11.4
Total Foreign	3.43	3.36	-2.0	0.92	0.83	-10.1	4.35	4.19	-3.7
Worldwide Total	3.42	3.39	-0.8	0.80	0.74	-7.1	4.22	4.13	-2.0

-- = Data not available.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Effective rates of taxation (actual income tax expense as a percentage of pretax income) on oil and gas income have been generally declining for nearly two decades. In the United States, the effective rate of income taxation on the FRS companies' oil and gas production operations averaged about 45 percent in

1981 to 1985, prior to the oil price crash of 1986, but was down to 30 percent in 1997. Abroad, the comparable decline was from 69 percent to 50 percent. When the effective tax rate includes the effects of production taxes, the decline in the impact of taxation on oil and gas income is even steeper (Figure 17). Clearly, Figure 17 shows that the fiscal take on income from oil and gas production has been in a steady long-term decline in the United States and abroad.

Figure 17. Effective Tax Rates (Income and Production Taxes) in Oil and Gas Production for FRS Companies, 1981-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Endnotes

[58] "Japan," *WEFA World Economic Outlook: Developing Economics Pre-Meeting Forecast, Volume 1A (*November 1997), p. 3.51 and Table 1.0.
[59] "Chevron Reports Third Quarter Net Income of $727 Million, "*Chevron Corporation Press Release,* (October 22, 1997) p. 3. Other majors reported similar results. Mobil said international earnings fell due to "lower income in Asia-Pacific resulting from generally weak business conditions ... region...." "Mobil Announces Record 1997 Operating Earnings of $3,430 Million," *Mobil Corporation News Release for the Financial Community* (January 28, 1998) p. 2.
[60]Texaco Corporation, *1997 Securities and Exchange Commission Form 10-K*, p. 2.
[61] Exxon Corporation, 1997 *Securities and Exchange Commission Form 10-K*, pp. F-4, and F-27.
[62] The FRS companies reporting that European refining/marketing operations benefited from the recovery of refining and marketing margins were Texaco, which reported "higher earnings in manufacturing, we improved refining operations , increased margins... in the United Kingdom, ... Marketing results also significantly improved ... recovery of margins in the United Kingdom," (Texaco Corporation, *1997 Annual Report*, p. 31) and Mobil, which said "operating earnings were $750 million, $71 million higher than in 1996 primarily due to benefits from the Mobil/BP alliance and stronger integrated margins in Europe," Mobil Corporation, *1997 Annual Report*, p. 25.
[63] The correlation between annual U.S. refining/marketing profitability and the net margin is 0.92, with 1.0 denoting perfect correlation. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability*, http://www.eia.doe.gov/emeu/perfpro/ref_pi/keyfind.html (November 17, 1998).
[64] Energy Information Administration, *Short-Term Energy Outlook*, http://www.eia.doe.gov/emeu/steo/pub/contents.html (November 17, 1998), Table A2.
[65] Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), Table 5.11.
[66] FRS companies with continuing U.S. refining and marketing operations are those that both were in the FRS group and had U.S. refining and marketing operations for both 1996 and 1997.
[67]For example, see Exxon Corporation, *Annual Report 1997*, Refining and Marketing (October 25 1998), pp. 1 and 3 (http://www.exxon.com/exxoncorp/news/publications/annual_97/annual_refining.html); and Coastal Corporation, “Refining, Marketing, and Chemicals” (October 25, 1998), p. 2 (http://www.coastalcorp.com/rmc/main.htm).
[68] This trend continued through 1997 as Texaco reported that it received $13 million for the sale of its credit card operation. See Texaco, *1997 Annual Report*, p. 31.
[69] For example, during 1997 both Exxon and Phillips mentioned in their annual reports that cogeneration plants had been completed at refineries, or were under construction. See Exxon Corporation, *1997 Annual Report*, p. 12 and Phillips Petroleum, *1997 Annual Report*, p. 16.
[70] Energy Information Administration, Form EIA-28, "Financial Reporting System."
[71] Catalytic cracking is the refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil. Catalytic cracking processes fresh feeds and recycled feeds. A fresh feed is crude oil or petroleum distillates, which are being fed to processing units for the first time. A recycled feed is one that is continuously fed back for additional processing. Catalytic reforming is a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low-octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline. Catalytic reforming is reported in two categories, low pressure and high pressure. A low-pressure unit operates with less than 225 pounds per square inch gauge (measured at the outlet separator) and a high-pressure unit operates with 225 (or more) pounds per square inch gauge. See Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(97)/1 (Washington, DC, June 1998), pp. 126-127.
[72] Higher quality products are those such as motor gasoline, jet fuel, and aviation gasoline. Alternatively, lower quality products are those such as residual fuel oil.
[73] The quality cost spread is the difference between the prices of higher quality (i.e., lighter and sweeter) crude oil and lower quality (i.e., heavier and more sour) crude oil. The relative viscosity of crude oil is determined by its API gravity. Light crude generally has an API gravity of 38, or greater. Heavy crude oil has an API gravity of 22, or less. Intermediate crude

has an API gravity between 22 and 38. The amount of sulfur in crude oil determines whether the crude is considered sweet (i.e., it has a low percentage of its weight contributed by sulfur), or sour (i.e., it has a high percentage of its weight contributed by sulfur).

[74] Unusual items are gains and charges recognized in a company's income statement that are of a non-recurring natural and generally unrelated to current operations. See endnote 3 in Chapter 2 for more explanation.

[75] See the box entitled "Upstream in Venezuela" in *Performance Profiles of Major Energy Producers 1995,* DOE/EIA-0206(95) (Washington, DC, February 1997), p. 31.

4. Emerging Patterns: Changes in Market Structure and Resource Development Activities

The detailed financial and operating data and information submitted each year to the EIA by major U.S. energy companies enables an examination of annual trends in the financial performance and profitability of the U.S. energy industry. However, the data are not by any means limited to this use.

In fact, the Financial Reporting System (FRS) data also permit analyses of new developments and emerging directions of the larger energy industry. Further, when the FRS data are combined with additional information from company annual reports, press releases, and other energy company public disclosures, the scope of energy industry financial analyses can be expanded. Additional analyses can then include issues related to the operations of independent energy companies (the "non-majors"), and to investments in lines of business outside of the traditional areas of oil and gas most strongly associated with the operations of the majors. The uniformity of the data reported to the FRS makes the available detail even more analytically useful, as data can be compared across lines of business (and across years) to elucidate trends and examine the significance of changes in trends.

This chapter of *Performance Profiles* provides a window to current and substantial changes occurring in the U.S. energy industry. In particular, these analyses discuss:

- a shift in the corporate emphasis of the major energy companies from one of downsizing and consolidation to one of corporate expansion;
- a reversal in the long-standing decline in oil and gas finding costs;
- the growth and operational expansion of independent U.S. oil and gas producers and U.S. refining/marketers, and the resultant blurring of the differences between their operations and those of the majors; and
- the beginning of investment by the majors in a worldwide electricity industry undergoing restructuring.

SPECIAL TOPIC: Corporate Growth Returns After a Long Absence

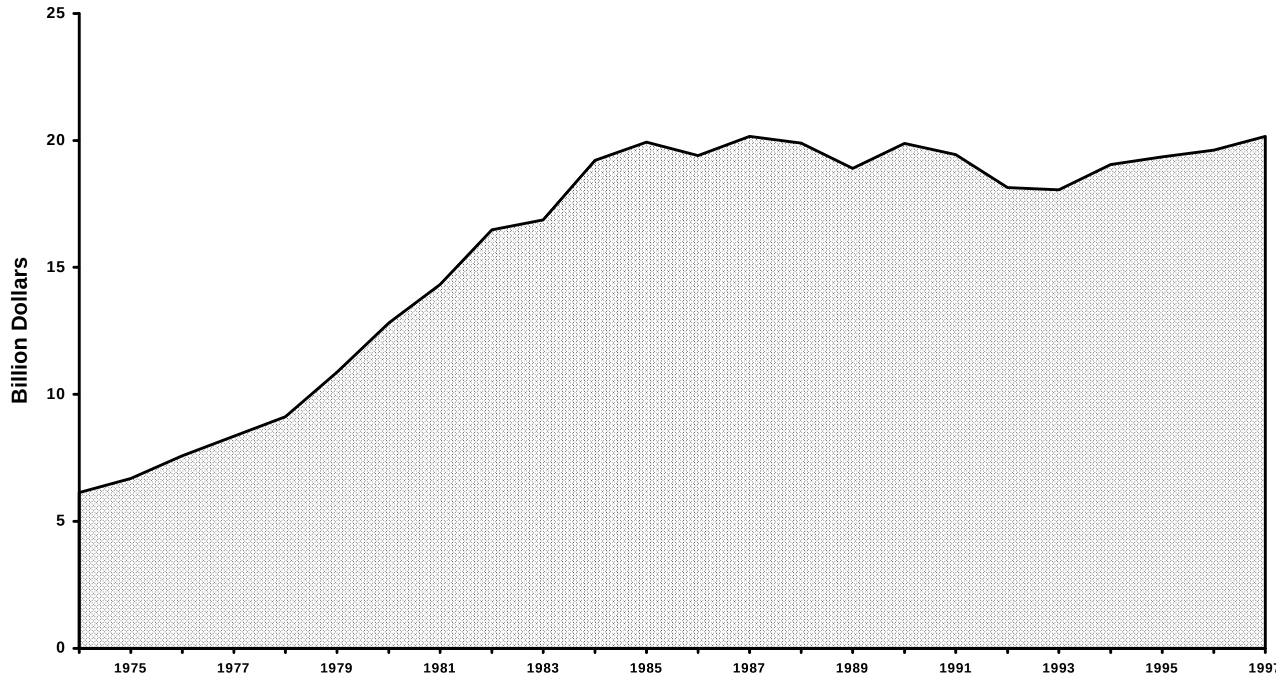
The FRS companies' recent financial performance and the surge in the capital expenditures indicate that the long-running asset consolidation and associated downsizing pursued by these companies might have now provided the platform for corporate growth.

A review of the companies' past record of corporate growth provides important perspective to the apparent emergence of a renewed emphasis in this area.

1974 to 1984: Investment Emphasizes Growth and Diversification

Prior to the mid-1980s, the FRS companies' total asset base nearly tripled in the context of escalating oil prices and expectations of rising oil prices into the indefinite future (Figure 18). Oil and gas exploration and production in the United States was the primary target of this surge in investment. Forty-two percent of the FRS companies' total capital expenditures in the 1974-1981 period were in the domestic upstream line of business.

Figure 18. Average Total Assets per Company for FRS Companies, 1974-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Two developments led to this emphasis on domestic oil and gas investment. First, many of the oil producing nations outside North America effectively placed themselves off limits or limited access to private investment by western companies. Barriers to private investment in these areas were erected through outright nationalization of oil and gas properties, implementation of highly constrained production agreements by host governments, and/or increased taxation of earnings from oil and gas production at near confiscatory rates. At the same time that access to foreign exploration and production activity was reduced, the FRS companies' cash flow was increasing sharply while U.S. demand for petroleum was growing. As a result, the FRS companies sharply increased their U.S. upstream exploration and development outlays beginning in the late 1970's.

Second, escalating oil prices, apart from their effects on cash flow, also encouraged a shift toward domestic upstream investment targets. Oil and gas deposits (termed field sizes) in the United States tend to be much smaller than in areas outside North America. Generally, smaller fields tend to be less economically attractive due to typically higher per-barrel development and production costs. However, despite the cost disadvantages that inhere in developing smaller fields, higher oil prices and expectations of continued oil price rises can elevate sub-marginal, small fields into a range of acceptable profitability.

The area of diversified businesses beyond energy and chemicals was also targeted by FRS companies for steep increases in investments during the era of oil price run-ups. A wide variety of business activities (both energy and nonenergy businesses) were added by the FRS companies. As noted in an earlier edition of *Performance Profiles*, "notable diversification moves included primary metals and nonfuel minerals mining, engineering and construction, real estate development, timber, agriculture, trucking, convenience stores, insurance, computer services, and direct mail retailing. Other pursuits appeared to be of a more conglomerate nature such as department stores, automobile parts, shipbuilding, meatpacking, and office and other electrical equipment."[a] These moves appeared to be predicated on the desire to achieve synergies through the application of expertise routinely utilized in integrated petroleum and chemicals operations. Also, diversification beyond petroleum and chemicals offered potential avenues of corporate growth and investment outlets for rapidly growing cash flows resulting from the price escalations of the 1974 to 1981 period.

1985 to 1992: Retrenchment and Consolidation

Beginning even before the oil price crash of early 1986, the FRS companies have implemented strategies that emphasized selective retrenchment of some businesses and consolidation of remaining operations. These strategies were driven by a number of necessities. First, there was a need to increase shareholder value (an objective imposed by the capital markets' relentless search for growth in equity value). Secondly, there was the necessity to find asset configurations that could withstand the rigors of oil prices that were likely to fluctuate indefinitely within a range of $10 to $20 per barrel. Further, at the same time, investment opportunities and added attractions to existing operations were being made possible by market developments, technological advances, and changes in government policies.

In pursuing greater shareholder value, the FRS companies have become more specialized through consolidating their assets and focusing their investments around core competencies. However, the emphasis on consolidation (though possibly increasing per-share equity values) can also either produce stasis or decline in a corporate entity. These latter outcomes, though viable on a transitional basis, raise questions about the possibility of long-term viability without growth.

From the mid-1980's until about late 1992 or early 1993, retrenchment and consolidation reduced the FRS companies' corporate growth to virtually nil, as annual decreases in the asset base were about as frequent as increases (Figure 18). The bulk of the assets shed during this period were from U.S. oil and gas production with diversified nonenergy enterprises accounting for most of the balance (Figure 19). These were the same areas that had been the focus of increased investment in the period of rising oil prices.

After the 1986 world oil price crash, four areas were growing noticeably for the FRS companies. The foreign upstream line of business attracted the most investment due to the larger field sizes outside North America and a generally more accommodating policy by many oil-producing nations toward oil and gas investment by western corporations. The significantly lower petroleum product prices following the oil price crash of 1986 and its aftermath stimulated petroleum product demand and reduced chemical feedstock costs. Also, the overall global economic growth of the late 1980's, particularly in the Asia-Pacific region, increased petroleum and chemical demand. As a result, in addition to their focus on investment in foreign upstream, the FRS companies also shifted investment to petroleum refining and marketing and chemical manufacturing. Lastly, in the 1990's, domestic environmental requirements, particularly the Clean Air Act Amendments of 1990 and reformulated fuel standards in California, translated into added investments in U.S. refining. However, although investment targets shifted during the 1985-1993 period, entailing some $448 billion in capital and exploratory expenditures by the FRS companies, overall corporate growth was essentially absent.

1993 to 1997: A Return to Corporate Growth?

The year 1993 appears to have marked a turning point in corporate growth of the FRS companies. By 1993, the average size of the FRS companies reached a low in the post-1986 era, some 10 percent below the peak value of 1987. By contrast, the S&P Industrials' average total assets grew by 80 percent, excluding the FRS companies. Since 1993, the FRS companies' average asset base has grown at an annual rate of 3 percent, the highest 5-year growth rate since the mid-1980's (Figure 20).

The core areas of growth between 1993 and 1997 were largely the same as in the 1985 to 1993 period--foreign oil and gas production, chemicals, and foreign refining/marketing (Figure 19). The other energy line of business (which consists mainly of electricity projects pursued by a minority of FRS companies) registered the steepest rate of growth, 14 percent during this period. Upstream assets in the United States increased slightly, ending a long-running decline, mainly due to outlays for projects in the Gulf of Mexico. However, whether the 1997 uptick in corporate investment is a one-year event or the onset of a new trend is yet to be determined.

[a] Energy Information Administration, *Performance Profiles of Major Energy Producers 1993,* DOE/EIA-0206(93) (Washington, DC, January 1995), p. 52.

SPECIAL TOPIC: Electricity Restructuring Attracts the U.S. Majors

Choice Drives Electricity and Natural Gas Marketing Combinations

The electric power industry generated 3.5 trillion kilowatthours of electricity in the United States in 1997.[a] Eighty-eight percent of all electric power generation was produced by electric utilities with the remaining share accounted for by nonutility power producers. Electric utilities preference for energy sources to generate electricity varied while nonutility power producers preferred natural gas 2-to-1.[b] For electric utility companies, coal-fired generation totaled 51 percent, nuclear power accounted for 18 percent, hydroelectric power total 10 percent and natural gas accounted for 8 percent.[c]

Although natural gas only accounted for a small share of electric power generation for utilities, a recent report by the Energy Information Administration forecast that electric utilities' natural gas consumption would almost double between 1996 and 2015. The growth in the use of natural gas for electric power generation is expected in response to a number of interrelated developments. The anticipated deregulation of electric power by state agencies and the Federal Energy Regulatory Commission (FERC), and the resulting restructuring of the U.S. electricity industry, are expected to generate additional natural gas demand, as will the anticipated construction of new gas-fired turbines and combined-cycled facilities.[d]

On April 24, 1996, FERC issued Orders 888 and 889. The Orders require all public utilities that transmit electric energy in interstate commerce to (1) have open access nondiscriminatory transmission tariffs, (2) use transmission services for their own new wholesale sales and purchases of electricity under open access tariffs, (3) develop and maintain a transmission system that would allow users equal access to transmission information, and (4) separate the vertically integrated industry into three separate entities: generation, transmission, and distribution.[e] The full implementation of these Orders, along with deregulatory measures anticipated by the States, is expected to create a more competitive wholesale and retail market that will exist allowing consumers to purchase directly from generators or from the retail suppliers of their choice.

It appears that this prospect of greater consumer choice is the catalyst behind combinations now being seen between natural gas and electric power industries. Combinations of electrical and natural gas assets are also attractive because of the previously mentioned anticipated doubling of the demand for natural gas for electric generation by utilities.

Figure 19. Net Investment in Place by Lines of Business for FRS Companies, 1985, 1993, and 1997

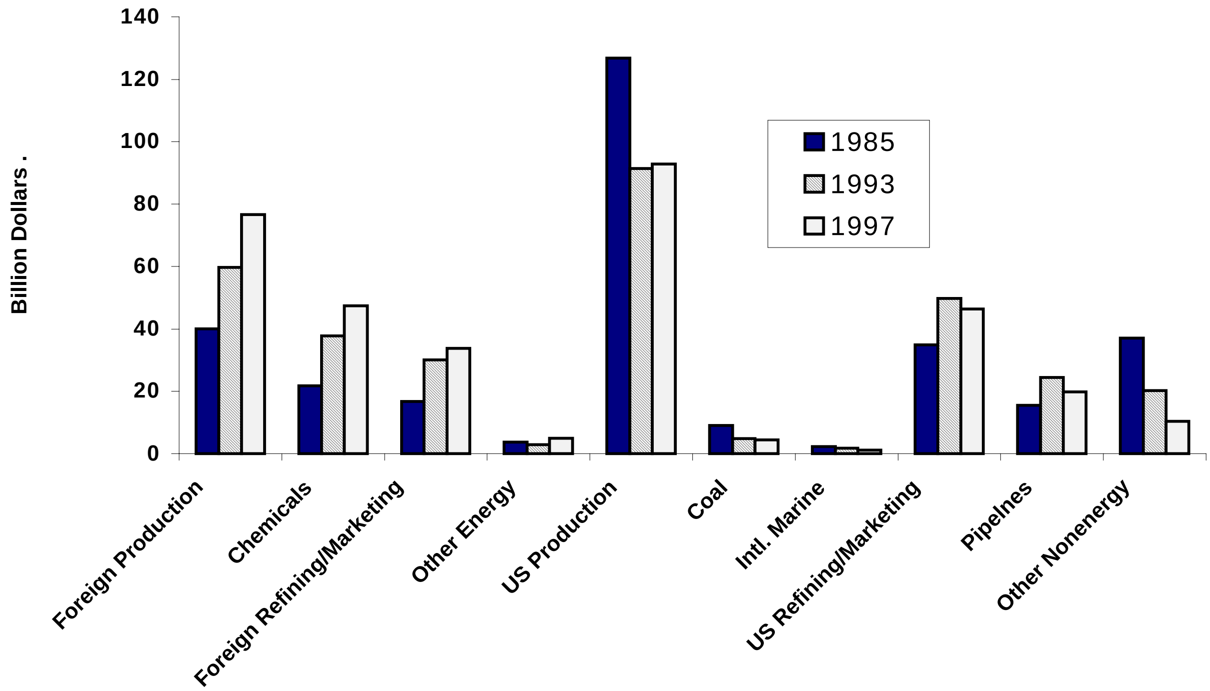
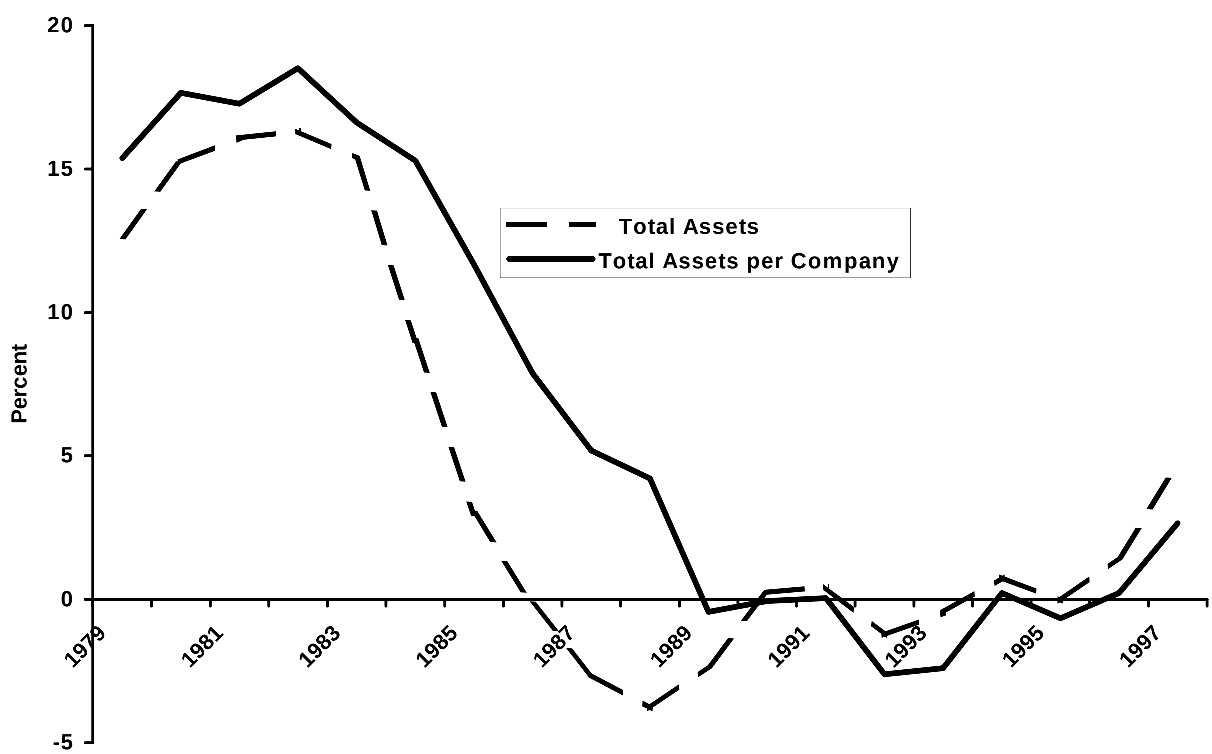


Figure 20. Annualized Five-Year Growth Rates for FRS Companies, 1979-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Numerous merger, acquisition and joint venture activities between the electric power and natural gas industries occurred in 1997-98 (Table 19). This trend between the two industries is known as energy convergence. Energy convergence is the ability to interchange various sources of energy, (such as natural gas and electric) over time, location and form through a common currency --- the Btu.[f] Industry combinations include: (1) electric utilities acquiring pipelines, local distribution companies (LDCs), and coal mines; 2) major oil companies acquiring midstream natural gas and electric-generating assets; 3) pipelines acquiring electric utilities, and independent power producers; 4) pipelines acquiring gatherers, processors and marketers, and other pipelines; 5) LDCs acquiring other LDCs.

Table 19. Merger/Acquisition Activity Between Electric Utility and Natural Gas Industries in 1997 and 1998[a]

Companies	New Entity	FERC Approval
Enron Corp and Portland General Corp	Enron Corporation	1997
Duke Power and Panergy	Duke Energy	1997
Houston Industries and Noram Energy	Houston Industries	1997
Brooklyn Union Gas (Keyspan) and Long Island Lighting Co.	MarketSpan	1998
Louisville Gas and Electric Energy (LG&E) and Kentucky Utilities (KU)	LG&E	1998
Pacific Enterprises and Enova	Sempra Energy	1998
Pacific Gas & Electric and Valero Energy	Pacific Gas & Electric	1998
TECO Energy and West Florida Gas	TECO Energy	1997
Texas Utilities and Enserch Corporation[b]	TUC Holding Company	1997
Southern Energy and Vastar Company	Southern Company Energy Marketing	1997

[a]The merger/acquisition table includes transactions before August 1998. Sources: *Electric Light and Power*, "Industry Report; Mergers Thin Ranks of IOU: Thin Ranks of IOU: Only 99 Left" (August 1998), p. 21; *Inside F.E.R.C*., "Merger Policy Broke FERC Logjam, But Overall Process Remains Arduous", October 1997, p. 1.; and MLR Publishing Company, *Mergers and Acquistions*, "Engineering Exotic Blend in Utility Mergers," September 1997/October 1997, p. 47.

[b]Southern Energy and Vastar Company formed an alliance merger which combined certain natural gas and power trading and marketing operations. Source: Vastar Company, *Securities and Exchange Commission 10Q Form,* September 30, 1997.

Some companies (those which are primarily engaged in electricity operations) have strategically acquired natural gas assets[g] to increase their competitiveness in the emerging market structures through lower operating costs, diversified operations, broadened marketing potential, and an expanded customer base.[h] Electricity-natural gas combinations in overlapping geographic markets can lower operating cost through the elimination of duplication in services, such as meter reading, accounting, and billing statements. In addition, broader menu services can be offered to customers, such as energy management.

Companies with the capability to offer electricity and natural gas can attract new customers or retain current customers, particularly large commercial and industrial users, by supplying either natural gas or electricity, whichever is the lower-priced fuel at the time. In warmer temperatures, for instance, natural gas prices are lower compared to electricity prices. Conversely, a company can take advantage of multi-fuel availability and increase its marketing margins by selling high price fuels during peak periods and/or transporting natural gas from one region to another. For example, natural gas in the

Northeast and Midwest during the summer months can be used to generate electricity in the winter when electric prices are higher. In addition, increased margins could be achieved through the transportation of natural gas and electricity from one region that commands lower prices to another region that commands higher prices.

Major U.S. Energy Companies Commit to Electric Power

Enron, one of the Financial Reporting System (FRS) companies, became one of the largest wholesalers of electricity in North America in 1997 with the purchase of Portland General Corporation (PGC). PGC, a wholly owned subsidiary of Portland General Electric Company, serves retail electric customers in northwest Oregon and also sells wholesale electric power throughout the western United States. (According to the *Electric Light and Power* annual report, Enron was the largest U.S. revenue-based investor-owned electric utility company in 1997, primarily due to its wholesale energy marketing activities. However, Enron has considerable operations other than electricity (such as natural gas production and marketing); when the company's other activities were excluded and revenue was based only on electric revenue, Enron ranked 14th in the United States.[i]) In addition to its wholesale electricity operations, Enron also has electric generation operations in the United States, and has had overseas investments since 1989 in Europe.[j]

Other FRS companies are also making commitments to U.S. electricity. The Mobil Corporation purchased a 40-percent interest in the recently merged Duke-PanEnergy's marketing division, PanEnergy Trade. The marketing division will promote Mobil's symbol of the flying horse to market electricity and natural gas. Conoco (Dupont's energy subsidiary) formed a joint venture with American Electric Power. The new entity, AEP Conoco Energy Capital, will purchase and lease back energy assets to industrial and large commercial plants, and will provide customers with management services.[k] Sonat, a new entrant to the FRS survey in 1997, created a new power marketing division to take advantage of opportunities in wholesale power marketing. In addition, the company purchased a 50-percent interest in a 300-megawatt, natural gas-fired combined cycle cogeneration facility megawatt from GPU International. After the plant comes on line in June 1998, power will be sold to Georgia Power, the local power company, during peak periods.[l]

Some FRS companies also have domestic and overseas power operations. As in the United States, the biggest player (among the FRS companies) in overseas electricity is Enron. Currently, Enron has electricity or electricity/gas projects in England, China, the Dominican Republic, Germany, India, Indonesia, Italy, Puerto Rico, and Turkey.[m] Exxon has had power operations for more than 30 years in the U.S. and has operations aboard in China, Hong Kong, Japan, Mongolia.[n] Coastal, another FRS company, has power operations in the United States and abroad in the Caribbean, China, El Salvador, Guatemala, Nicaragua, and Pakistan, and Thailand.[o] Exxon and Coastal both have domestic cogeneration operations at their refineries, which help to lower operating costs and increase efficiencies.[p] Coastal sells its excess power wholesale to the local electric power plant. Exxon recently built its cogeneration plant at its Baytown, Texas refining and chemical complex in 1997 (expenditures for the new plant were reported in the
refining and marketing segment). Overseas, Unocal has geothermal power projects in California and in Indonesia,[q] and has a gas-fired project under construction in Thailand.[r] Chevron and Texaco (through its subsidiary Amoseas Indonesia) also has geothermal power projects in Indonesia.[s]

[a] The electric power industry is comprised of electric utilities and nonutility power producers. Electric utilities are public agencies and privately owned companies which generate power for public use and are regulated by the Federal Energy Regulatory Commission. There are five types of utilities. Nonutility power producers are privately owned entities that generate power. They are unregulated power producers of the industry.

[b] Other fuels consumed for electric generation included petroleum, natural gas, steam coal, nuclear power, renewable energy and electricity. Source: Energy Information Administration, *Monthly Energy Review, October 1998*, DOE/EIA-0035 (98/10), Table 7.5.

[c] Other energy sources used to generate electricity accounted for 13 which include petroleum, geothermal energy, wood and waste, and other (wind, photovoltaic and solar thermal energy sources). Source: Energy Information Administration, *Monthly Energy Review, October 1998*, DOE/EIA-0035(98/10),Table 7.1.

[d] The Energy Information Administration conducted a quantitative analysis to determine the impact of competitive electricity generation markets on fuel supply industries. Three possible analysis cases were tested based on different assumptions regarding electricity and energy variables. The first two cases assumed full competition (assumed low and high fossil fuel consumption), and the third case assumed a partial competition case. All three cases were compared with a no competition case in order to illustrate the possible impacts of competition. The study showed in all three cases (1) natural-gas-fired turbines and combined-cycle plants would be the preferred fuel for new generating capacity when additional competition was assumed, and (2) restructuring in the electric power industry would stimulate the demand for natural gas. Energy Information Administration, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers (* September 1998)
http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/html/frontintr.html

[e] For a more in-depth discussion see Energy Information Administration, *The Restructing of the Electric Power Industry*, http://www.eia.doe.gov/cneaf/electricity/chg_str/brochure/toc.html

[f] "Natural Gas Pipeline/LDCs-Industry Report" *The Investext Group Industry Report, Report No:2619445*, (January 28, 1998), p. 16.

[g] Natural gas assets include natural gas storage facilities, transmission and distribution.

[h] ,"Engineering Exotic Blends In Utility Mergers," MLR Publishing Company, *Mergers & Acquisitions* (September 1997 / October 1997), p. 47.

[I] Duke Energy ranked second based on total revenue which also included wholesale marketing operations. However, excluding marketing operations the company ranked 13 based on electric revenue. "Industry Report-Mergers Thin Ranks of IOU: Only 99 Left," Electric Light & Power (August 1998), p. 21.

[J] Enron Corporation, 1997 Securities and Exchange Commission 10-K Form. http:www.sec.gov

[k] "Oil and Gas Interests Newsletter," *Phillips Business Information, Inc*., Vol. 11, No. 147 (November 1, 1997), p. 6.

l Sonat Corporation, *1997 Securities and Exchange Commission Form 10-K*, p. I- 21; and "Sonat Energy Services Purchases 50-percent Interest in Georgia Power Plant," *Sonat Corporation Press Release*, (February 26, 1998), p. 1.

m Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, pp. 11 and 12.

[n] Exxon Corporation, *1997 Annual Report*, pp. 12 and 19.

o Coastal Corporation, *1997 Securities and Exchange Commission Form 10-K*, p. 19, and *1997 Annual Report*, p. 31.

[p] Exxon Corporation, 1997 Annual Report, pp. 12, and 19; and Coastal Corporation, *1997 Securities and Exchange Commission Form 10-K*, p. 19, and *1997 Annual Report*, p. 31.

[q] Unocal sold Unocal sold 80 percent of its interest in the subsidiary, NEC Acquisition Company, that owns a 25 percent interest in geothermal energy at The Geysers in Northern California. Source: Unocal Corporation, *1996 Annual Report*, p. 21.

[r] Unocal Corporation, *1997 Annual Report*, pp. 20 and 26.

s Chevron Corporation, *1997 Annual Report*, p. 20.

SPECIAL TOPIC: U.S. Downstream Independents Acquire National Prominence in the 1990's

U.S. Refining Assets Undergo Significant Redistribution

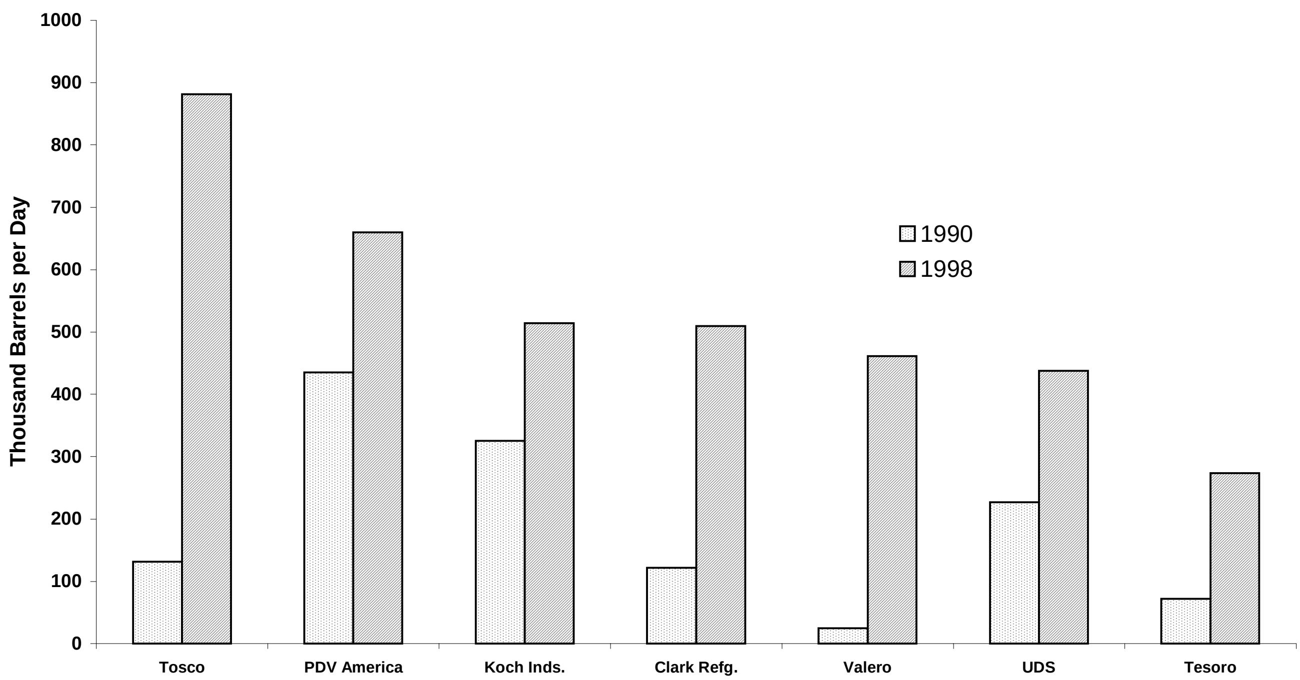
Due to a long period of low profitability in the refining/marketing line of business, U.S. integrated major energy companies began a process during the 1990's of selective refining/marketing divestiture. During the same period, 42 refineries (constituting 20 percent of those in operation in the United States during 1990) were shut down.

The availability of the majors' downstream assets created an opportunity for smaller, independent U.S. refiner/marketers to acquire domestic refineries and petroleum marketing outlets and move into market areas formerly dominated by the majors. (For the purposes of this report, an independent refiner/marketer is defined as one that has no significant crude oil production.) As a result, a large amount of FRS refining and marketing assets changed hands in the 1990's.

Initially, one independent refiner/marketer (Tosco Corporation) was willing to absorb the risk inherent in acquiring these assets. A small number of other independents subsequently pursued a similar acquisition and growth strategy. However, despite the significant shutdown of U.S. refineries and the substantial restructuring of the U.S. refining/marketing industry, overall crude oil distillation capacity in the United States only declined from 16.4 million barrels per day to 16.1 million barrels per day between 1990 and 1997.

Clearly, some refiners have been expanding the capacity of their refineries. An examination of the data indicate that the majors have added some capacity at the refineries which they retained, and other capacity gains have been made by the same independent refiner/marketers who undertook a growth strategy in the 1990's. Among independent refiners, growth has been largely concentrated in the following group of companies: Citgo/PDV America, Clark Refining and Marketing, Diamond Shamrock (merged with Ultramar during 1996, creating Ultramar Diamond Shamrock), Koch Industries, Tesoro Petroleum, Tosco Corporation, Ultramar, and Valero Energy (Figure 21).[a] As a group, they owned 12 refineries with a combined refining capacity of slightly more than 1.3 million barrels per day in 1990, about 8 percent of total U.S. refining capacity.[b] By October 1998, the companies owned a total of 29 refineries with a combined refining capacity of approximately 3.7 million barrels per day, about 23 percent of total U.S. refining capacity (Figure 22).[c]

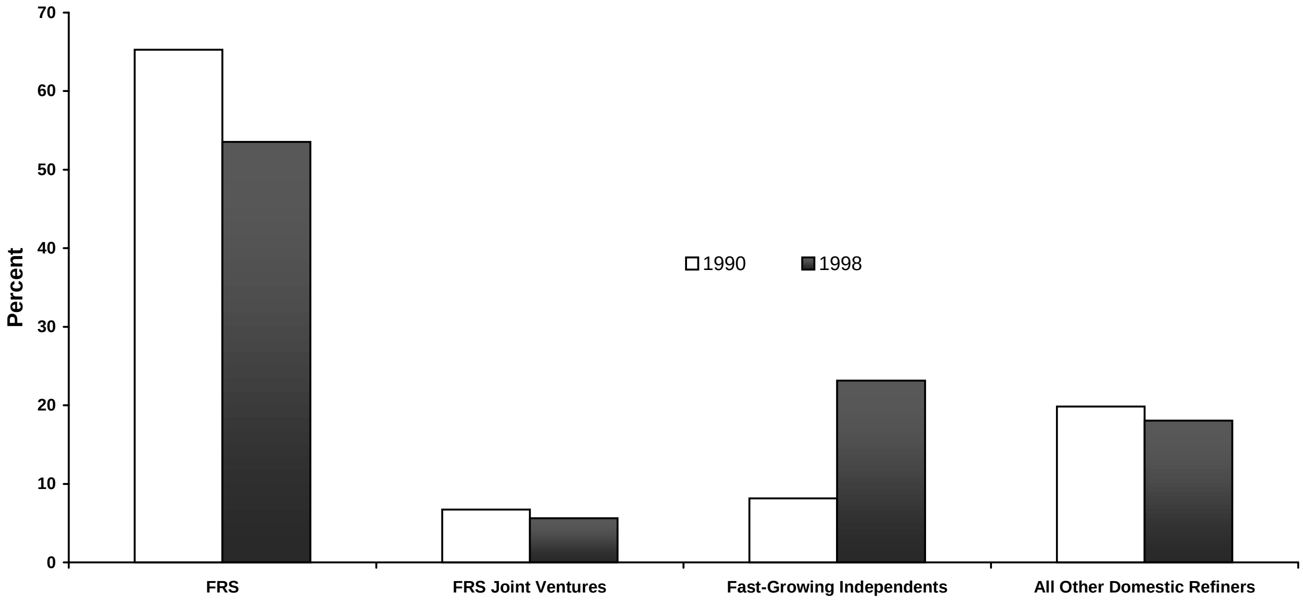
Figure 21. U.S. Crude Oil Distillation Capacity of Fast-Growing Refiners, 1990 and 1998



Sources: Energy Information Administration, *Petroleum Supply Annual 1990*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, May 1991), Table 39; Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington,DC, June 1997), Table 40; Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, June 1998), Tables 37 and 38; and various news sources.

The near-tripling of the refining capacity of this group was largely accomplished through acquisition of refining capacity (88 percent), 66 percent of which was acquired from the integrated major energy companies reporting to the Financial Reporting System (FRS) (Table 20). Recent acquisitions by Tosco (since April 1993) include six refineries from these companies (Exxon-1, BP-2, and Unocal-3) with a total refinery capacity of 747,000 barrels per day (b/d). Also, near the end of 1996, Diamond Shamrock (which had a refining capacity of 223,000 b/d) merged with Ultramar (which had a U.S. crude distillation capacity of 68,000 b/d).[d] Since then, the resulting company (Ultramar Diamond Shamrock) has acquired Total Petroleum's distillation capacity of 141,600 b/d,[e] as well as control of Phillips Petroleum's 345,000 capacity through the formation of a new Ultramar-Phillips joint venture, Diamond 66.[f] Overall, the rate of refining capacity acquisition in the United States has been especially high during 1998. Thirty-three percent of the capacity acquired between 1991 and October 1998 was acquired during 1998.

Figure 22. Percentage of U.S. Crude Oil Distillation Capacity, by Category, 1990 and 1998



Sources: Energy Information Administration, *Petroleum Supply Annual 1990*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, May 1991), Table 39; Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 40; Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, June 1998), Tables 37 and 38; and various news sources.

Table 20. Fast-Growing Independents' Refining Capacity and Acquisitions, 1990 and October 1998
(Thousand Barrels Per Day)

Company	1990 Crude Oil Distillation Capacity	Capacity Additions			October 1998 Crude Oil Distillation Capacity
		Acquisition of FRS Refineries	Acquisition of Other Refineries	Refinery Expansion	
Tosco	131.9	699.3	0	50.3	881.5
PDV America	435.0	181.7	0	43.0	659.7
Koch Industries	325.0	104.0	0	85.0	514.0
Clark Refining	121.6	346.5	0	41.4	509.5
Valero Energy	25.0	152.0	279.6	4.9	461.5
Ultramar Diamond Shamrock	227.0	0	147.0	64.0	438.0
Tesoro Petroleum	72.0	108.2	95.0	-1.5	273.7
Total	1,337.5	1,591.7	521.6	287.1	3,737.9

Sources: Energy Information Administration, *Petroleum Supply Annual 1990*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, May 1991), Table 39; Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington,DC, June 1997), Table 40; Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(90)/1 (Washington, DC, June 1998), Tables 37 and 38; and various news sources.

The large amount of downstream acquisition activity during the 1990's noticeably redistributed U.S. refining industry capacity. In 1990, the FRS companies (including their joint ventures) held 72 percent of U.S. refining capacity. The independent refiner/marketers who pursued acquisition growth strategies in the 1990's (the "fast-growing independent refiners") then held only 8 percent of domestic capacity, with 20 percent being held by all other refiners. By October 1998, the FRS share of domestic crude distillation capacity had fallen to 54 percent (60 percent including their joint ventures), and the fast-growing independent refiners had earned their name by increasing their share to 23 percent, an almost threefold increase. The remaining capacity (18 percent) is still held by all other refiners (Figure 22).

Gasoline Marketing Operations Also Expand

Gasoline marketing in the United States has undergone dramatic changes over the past 15 years. Not only has the crude distillation capacity of the fast-growing independent refiners grown markedly since 1990, so too has their presence in gasoline retailing, as measured by number of motor gasoline retail outlets.

The major U.S. oil companies have refocused their marketing operations, concentrating operations in those regions in which they have had the most success, i.e., where they have achieved the greatest profitability or the greatest market share. The average number of states in which the FRS companies have operations declined from 28 states in 1990 to 25 states in 1997 (Table 21). However, this decline is only part of the consolidation story, as the FRS companies also have substantially fewer branded outlets.

Table 21. Branded Retail Outlets of FRS and Fast-Growing Independent Refiners, 1996-1997

	Average Number of States with Branded Outlets		Number of Branded Outlets	
Group	1990	1997	1990	1997
FRS	28	25	51,085	33,753
Fast-Growing Independent Refiners	14	24	13,117	25,248

Sources: *National Petroleum News*, *1991 Factbook* (mid-June 1991), pp. 44-51; and *National Petroleum News*, *Market Facts 1998* (mid-July 1998), pp. 44-52.

Total domestic FRS branded outlets (lessee and open dealers) declined from 51 thousand in 1990 to 34 thousand in 1997, a 34-percent decline over the period.[g] This decline is notable when compared to the 10-percent decline in the number of all U.S. gasoline stations (regardless of ownership) between 1991 and 1997.[h] The FRS companies' consolidation and refocusing of their marketing operations have resulted in their branded outlets declining at more than twice the national rate over the same period.

In contrast to the FRS companies, the fast-growing independent refiners have expanded their scope of operations, both through acquiring and opening new outlets. The number of branded outlets of the fast-growing independent refiners nearly doubled from 1990 to 1997, to 25 thousand. Rather than consolidating the geographic scope of their gasoline marketing networks (the concentration strategy pursued by the majors), the fast-growing independent refiners have expanded. For those independent refiners owning gasoline outlets in 1997, the average number of states in which they retail gasoline increased from 14 states in 1990 to 24 states in 1997.

Recent gasoline marketing acquisitions by independents include Tosco, which has added approximately 2,000 outlets (632 from BP and 1,317 from Unocal) since April 1993. Additionally, in 1996 Tosco acquired the Circle K convenience store chain and its 1,900 gasoline outlets. Prior to this acquisition, Tosco had owned relatively few convenience store operations. Also in 1996 (as previously mentioned), Diamond Shamrock (which had 1,324 retail outlets in eight different Midwestern states) merged with Ultramar (which had 420 outlets in California in late 1996) creating Ultramar Diamond Shamrock (UDS). Since then, UDS has acquired Total Petroleum, failed in an attempt to create a joint venture with Petro-Canada in the northeastern United States and Canada, and succeeded in creating a joint venture with Phillips Petroleum in 1998.

The UDS acquisition of Total Petroleum included a total of 560 outlets and 3 refineries with a distillation capacity of 141,600 b/d.[i] The UDS-Phillips joint venture, Diamond 66, includes all of Phillips' domestic downstream petroleum operations and will be controlled by UDS, which has a 55-percent share of the joint venture. UDS' participation in the Diamond 66 joint venture adds 6,530 outlets in 32 states to those already controlled by UDS. In addition, the joint venture is expected to generate annual cost savings of at least $50 million and a one-time saving of $250 million.[j] Thus, the significance of UDS and, more generally, the group of fast-growing independent refiner/marketers in the U.S downstream petroleum industry have become even greater.

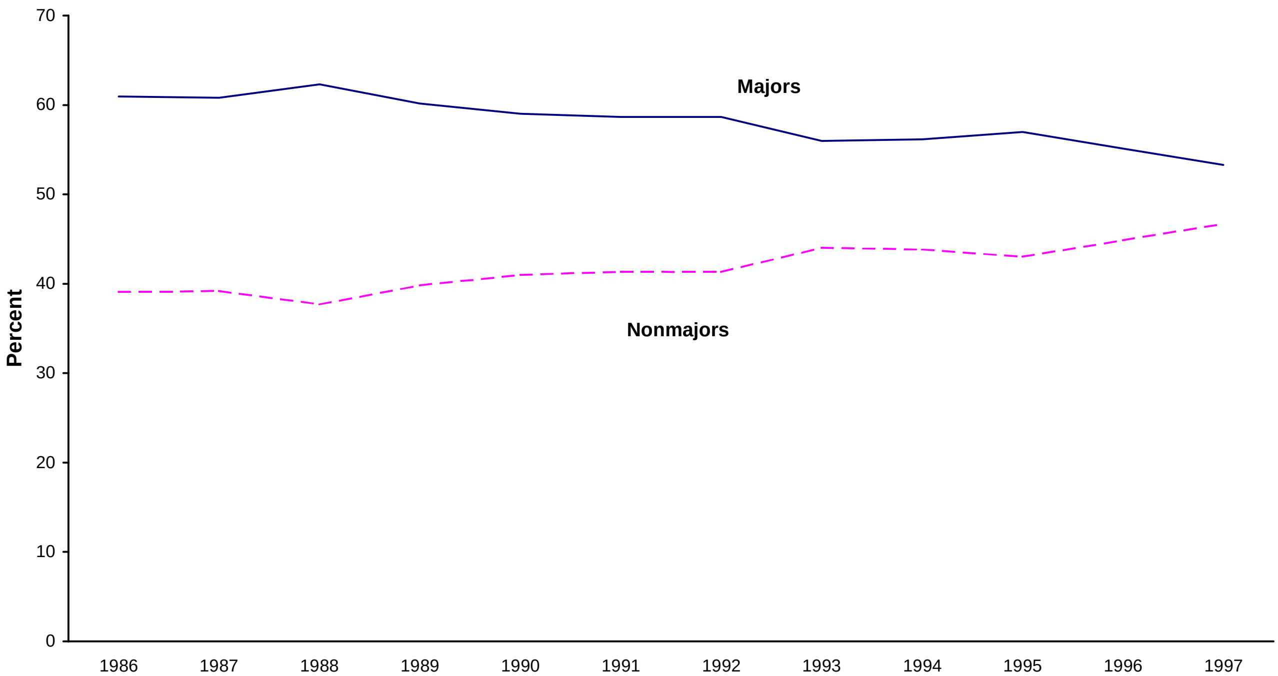
The rate of growth of the independent refiner/marketers discussed here may be described as ferocious. In particular, the downstream joint venture of one of the fast-growing independents (UDS) with one of FRS major energy companies (Phillips Petroleum) represented a new variation in the independent refiners' merger and acquisition trend. Such a substantial rate of growth suggests an obvious question, "How similar to the FRS companies do these independent refiner/marketers intend to become?" We look to the next year to provide additional insight into this question.

[a] During 1996 Ultramar and Diamond Shamrock merged, forming Ultramar Diamond Shamrock.
[b] Energy Information Administration, *Petroleum Supply Annual 1990*, Volume 1, DOE/EIA-0340(90)/1 (May 1991, Washington, DC), Tables 36 and 39.
[c] Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (June 1997, Washington, DC), Tables 36 and 40 and Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(97)/1 (June 1998, Washington, DC), Table 38.
[d] Ultramar also had substantial Canadian operations that became part of Ultramar Diamond Shamrock after the merger. Ultramar owned a 150,000 b/d refinery in Quebec, and a total of 1,341 retail outlets in Canada. Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 40; and National Petroleum News, *Market Facts '96*, Volume 88, Number 8 (Mid-July 1996), p. 80.
[e] Alan Kovski, "BP quitting Northwest with sale of refinery, outlets to Tosco," *The Oil Daily*, Volume 43, Number 187 (September 29, 1993), p. 3; Robin Sidel, "Tosco to Stay on Growth Track," Reuters Financial Service (February 16, 1996); and "Ultramar to Announce Purchase of Total U.S. Assets," Reuters Financial Service (April 15, 1997); Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 49; and Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(97)/1 (Washington, DC, June 1998), Table 38.
[f] "Ultramar Diamond Shamrock and Phillips Petroleum to Form Joint Venture Creating Largest Independent Refining and Marketing Company in North America," Business Wire (October 9, 1998).
[g] Energy Information Administration, Form EIA-28, "Financial Reporting System."
[h] A national estimate of the total number of motor gasoline retail outlets was not available for 1990.
[i] Alan Kovski, "BP quitting Northwest with sale of refinery, outlets to Tosco," *The Oil Daily*, Volume 43, Number 187 (September 29, 1993), p. 3; Robin Sidel, "Tosco to Stay on Growth Track," Reuters Financial Service (February 16, 1996); and "Ultramar to Announce Purchase of Total U.S. Assets," Reuters Financial Service (April 15, 1997); Energy Information Administration, *Petroleum Supply Annual 1996*, Volume 1, DOE/EIA-0340(96)/1 (Washington, DC, June 1997), Table 49; and Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0340(97)/1 (Washington, DC, June 1998), Table 38.
[j] "Ultramar Diamond Shamrock and Phillips Petroleum to Form Joint Venture Creating Largest Independent Refining and Marketing Company in North America," Business Wire (October 9, 1998).

Special Topic: Non-FRS Companies Challenge Majors in U.S. Oil and Gas Production

Production of oil and gas in the United States by non-FRS companies (including independent oil and gas producers, pipeline companies, foreign-based companies, and a variety of other companies) has generally been expanding since 1989. In 1995, the EIA published a report analyzing data through 1993 on U.S. oil and gas development that demonstrated that non-FRS oil and gas producers were playing an increasingly important role in U.S. oil and gas production. The most recent data, from 1994 through 1997, show that non-FRS oil and gas producers have continued to expand their role in U.S. oil and gas production. The share of oil and gas produced by non-FRS companies (on a barrel of oil equivalent basis (boe)) rose from 44 percent in 1993 to 47 percent in 1997 (on a net ownership basis[a]) (Figure 23). Production of oil (crude oil and natural gas liquids) by the FRS companies (i.e., the major integrated U.S. energy companies) has generally declined since 1987. While the FRS companies' domestic production of gas (dry natural gas) has increased, it has not grown quite as rapidly over the past decade as has gas production by non-FRS companies.

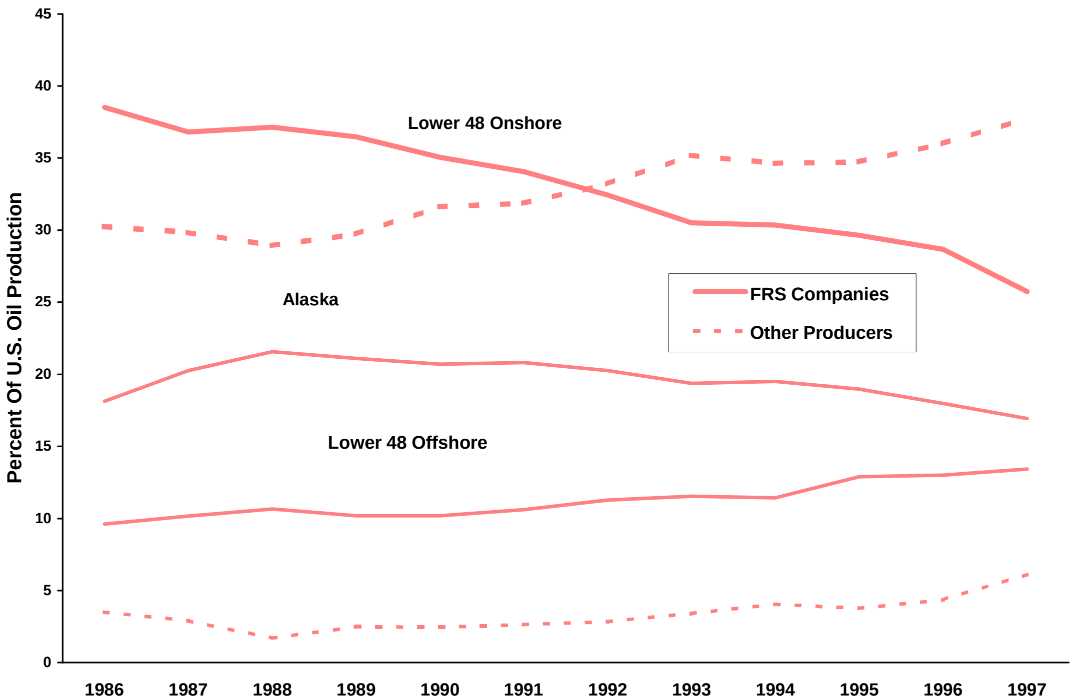
Figure 23. Shares of U.S. Oil and Gas Production (Net Ownership Basis) for Majors and Nonmajors, 1986-1997



Sources: **FRS Companies:** Energy Information Administration, Form EIA-28 (Financial Reporting System); **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report,* DOE/EIA-0216(97)Advance Summary (Washington, DC, September 1998), and preceeding issues.

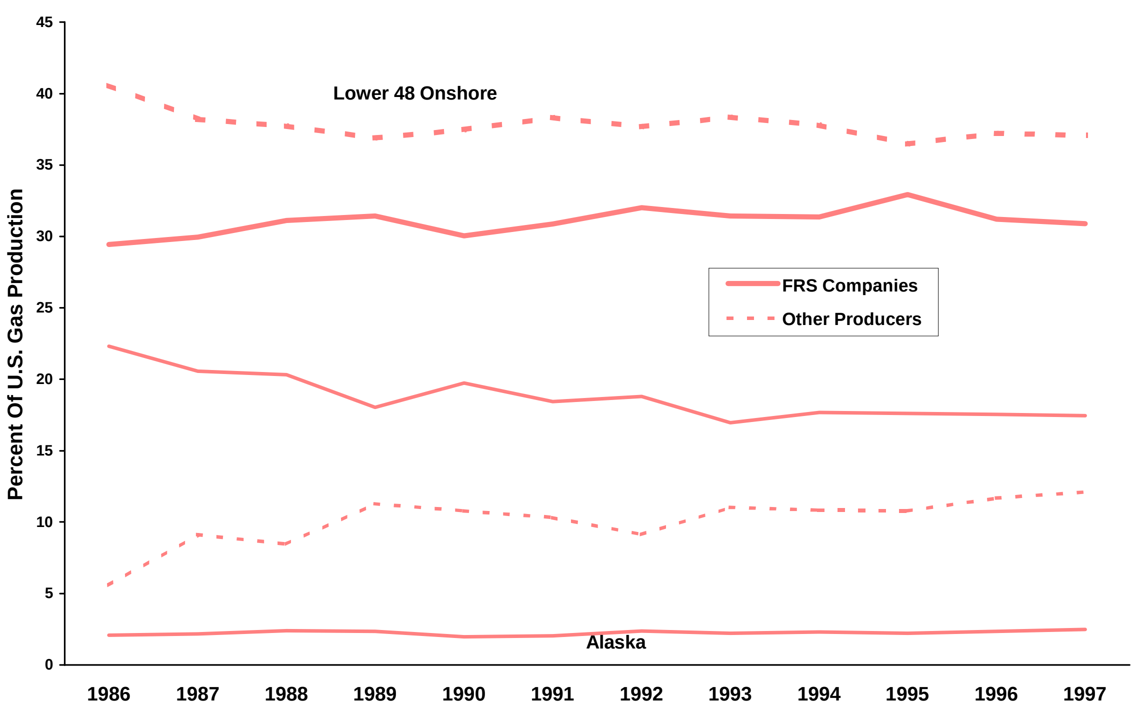
In 1997, the non-FRS companies produced an estimated 44 percent of U.S. oil, up from 39 percent in 1993. Non-FRS companies produced 49 percent of U.S. gas in 1997, the same share as in 1993. The non-FRS companies' gains varied by location. Overall, the largest increase in non-FRS company shares between 1993 and 1997 was in lower 48 onshore oil production (Figure 24). The non-FRS companies' share of lower 48 offshore production also rose, but it was still only 6 percent of the total in 1997. In contrast, for gas, the non-FRS company share of lower 48 onshore production has been essentially flat since the early 1990's, while their share of lower 48 offshore has increased slightly (Figure 25).

Figure 24. U.S. Oil Production Shares for FRS Companies and Other Companies, 1986-1997



Sources: **FRS Companies:** Energy Information Administration, Form EIA-28 (Financial Reporting System); **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report,* DOE/EIA-0216(97)Advance Summary (Washington, DC, September 1998), and preceeding issues.

Figure 25. U.S. Natural Gas Production Shares for FRS Companies and Other Companies, 1986-1997

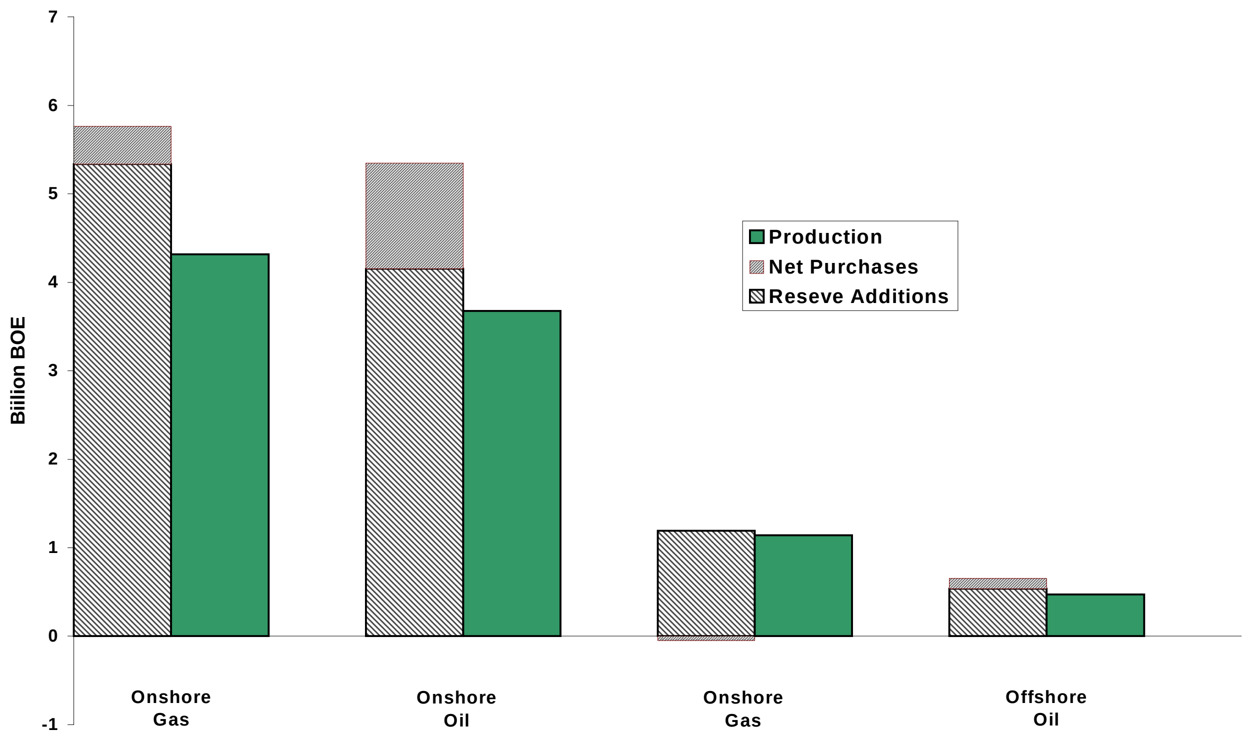


Sources: **FRS Companies:** Energy Information Administration, Form EIA-28 (Financial Reporting System); **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report,* DOE/EIA-0216(97)Advance Summary (Washington, DC, September 1998), and preceeding issues.

Non-FRS companies have also increased their amount and share of U.S. oil and gas reserves in recent years. The amount of the non-FRS companies' U.S. oil reserves increased 22 percent between 1993 and 1997, with all of the increase in the last 3 years. The FRS companies' U.S. oil reserves fell 9 percent over the same period; their U.S. oil reserves have fallen every year since 1988. The amount of non-FRS company gas reserves increased 11 percent from 1993-1997, most of it occurring in the past 2 years. The FRS companies' gas reserves decreased 3 percent over the same period. At the end of 1997, the shares of U.S. reserves held by non-FRS companies was smaller than their shares of production, at 38 percent of oil and 47 percent of gas.

In the 1989 through 1993 period, the reserves of the non-FRS companies in the United States declined. During this period, these companies did not have sufficient successful exploration and development activity to enable them to replace their production. In fact, even with purchases of reserves from the FRS companies, the non-FRS companies still could not replace all of their production. However, from 1994 through 1997, the non-FRS companies improved their exploration and development results substantially. This was true for oil and gas, both in the onshore and offshore. Purchases of the FRS companies' castoff properties are no longer necessary as a strategy to maintain reserve levels (Figure 26). This is not to say that the non-FRS companies have ceased all reserve purchases from FRS companies. Overall, such purchases have continued, especially for additions to oil reserves in the Lower 48 States. (Table 22).

Figure 26. Changes in End-of-Year U.S. Oil and Gas Reserves for Non-FRS Companies, 1993-1997



Sources: **FRS Companies:** Energy Information Administration, Form EIA-28 (Financial Reporting System); **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report,* DOE/EIA-0216(97)Advance Summary (Washington, DC, September 1998), and preceeding issues.

While the high productivity of the wells drilled in the offshore make it an attractive region in which to drill, the level of financial resources required to operate in this region is significantly higher than in the onshore. For example, in 1997, the average cost of drilling a well in the offshore was over three million

Table 22. Petroleum Reserves and Production for Nonmajors, 1994-1997
(Million Barrels of Oil Equivalent)

	Onshore		Offshore	
	Liquids	Gas	Liquids	Gas
Beginning-of-1994 Reserves	7,734	9,900	444	880
+ Reserve Additions, 1994-1997	4,157	5,337	535	1,192
+ Net Purchases from Majors, 1994-1997	1,195	427	118	-9
- Production, 1994-1997	3,670	4,317	450	1,140
= End-of-1997 Reserves	9,416	11,347	647	924

Note: Sum of components may not equal total due to independent rounding.

Sources: **Majors:** Energy Information Administration, Form EIA-28 (*Financial Reporting System)*; **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1994-1996 and Advanced Summary 1997 issues, DOE/EIA-0216 (Washington, DC, various).

Table 23. Average Daily Oil and Gas Production in the Outer Continental Shelf by Operator, 1997
(barrels of oil equivalent)

Company	Production	Company	Production
Shell	**568,931**	**Coastal**	**36,510**
Chevron	**427,581**	Pogo Producing	36,488
Exxon	**312,821**	Forcenergy	34,114
Texaco	**168,360**	Forest Oil	33,690
Unocal	**167,350**	**Phillips Petroleum**	**33,622**
Mobil	**146,413**	**Amerda Hess**	**32,296**
Pennzoil	129,180	SOCO Offshore	30,762
Amoco	**117,987**	CXY Energy Offshore	30,447
Atlantic Richfield	**94,648**	Agip Petroleum	29,392
USX	**88,410**	Ensearch Exploration	27,388
Newfield Exploration	81,530	Ocean Energy	27,094
Samedan Oil	80,973	Petsec Energy	26,363
Burlington Resources	**80,346**	Seneca Resources	24,842
BP America	**74,812**	Flextrend Development	24,001
Murphy Oil	71,288	**Anadarko**	**23,450**
Dupont (Conoco)	**70,041**	Seagull Energy	20,519
Sonat	**68,345**	Houston	19,810
Oryx Energy	**66,080**	Torch	19,257
Walter Oil and Gas	60,693	Santa Fe Energy Resources	15,613
Kerr-McGee	**57,982**	Energy Development	13,549
Norcen Explorer	54,656	Pioneer Natural Resources	11,954
Apache	51,423	**Union Pacific Resources**	**11,761**
CNG	50,693	American Exploration	11,083
Occidental Petroleum	**44,962**	Aviara Energy	11,020
Enron	**38,099**	Stone Energy	10,533

Note: The FRS companies are in bold. The data reflects production levels at the operator level and thus does not represent ownership interest. For those companies with more than one operating unit, production was aggregated across the operating units. The above values are field production levels which may not equal marketed production. Wet gas was converted to its oil equivalent using the conversion factor 0.19 barrels of oil per thousand cubic feet of natural gas. The above values do include lease condensate.
Source: U.S. Department of the Interior, Minerals Management Service

dollars or more than 10 times the average cost of drilling a well in the onshore. Given these larger financial requirements, offshore production has historically largely been the domain of the FRS companies, the industry's largest firms. Indicative of this, nine of the top ten offshore operators in 1997 were FRS companies (Table 23). On an operator level basis, the FRS companies in 1997 accounted for

69 percent of average daily offshore production.[b] Although the FRS companies account for the bulk of offshore oil and gas production, the non-FRS companies have increased their presence over the past decade. Between 1987 and 1997, average daily production by the non-FRS companies increased 40 percent to 1.2 million BOE per day from 871,000 barrels. Over the same period, production by the FRS companies increased by a more modest 11 percent, from 2.5 million barrels per day to 2.8 million BOE per day (Figure 23).

As a result of this trend, the size distribution of production among the operators has become less concentrated. In 1997, the top ten operators accounted for 55 percent of offshore production as compared to 63 percent in 1987. As further evidence of this trend, the Herfindahl index of production declined from 567 in 1987 to 505 in 1997.[c]

[a] Net ownership includes all of a company's fractional ownership shares in oil and gas properties but excludes royalty interests.
[b]The only publicly-available, company-level data on offshore production are reported on an operator basis by the Minerals Management Service (MMS) of the U.S. Department of the Interior. In other words, each operating unit reports its total production for the year to the MMS. In contrast, FRS data (used elsewhere in this Special Topic) are reported to the Energy Information Administration on a net ownership basis - that is, each company reports its proportionate ownership share of production. For the purposes of this Special Topic, this lack of perfect comparability does not appear to be a problem in that the FRS companies' share of offshore oil and gas production on an ownership basis is 66 percent and on an operator basis is 69 percent.
[c]The Herfindahl index is defined as the sum of the squares of the market shares (in percent) of each firm in the market. It ranges from zero to 10,000.

SPECIAL TOPIC: A Turnaround in Oil and Gas Finding Costs?

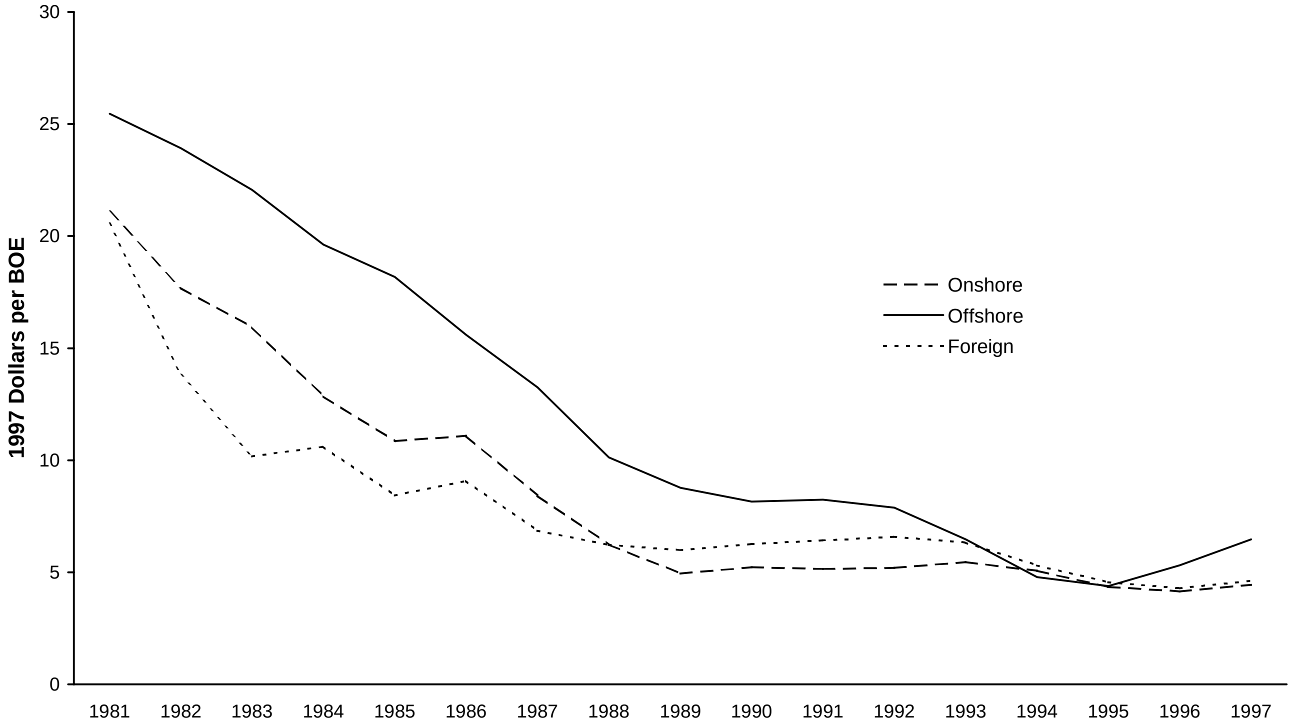
Increased Costs Primarily Offshore

Finding costs are the per-barrel costs of adding new oil and gas reserves (or replacing reserves removed through production) via exploration and development activity. Conceptually, finding costs are all the costs incurred (no matter when these costs were actually recognized on a company's books) in finding any particular reserves (except for purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (excluding the expenditures on proved acreage) to reserve additions, excluding net purchases, both the expenditures made and the reserves booked for the same period of time. The finding costs presented in this report, unless specified otherwise, are calculated for periods of three years.[a]

Finding costs for the FRS companies, overall and by region, have declined considerably since 1981, when oil prices and drilling activity were at all-time peaks. Based on 1997 dollars, the 1979-1981 oil and gas finding cost of over $20 per barrel of oil equivalent (boe) fell to less than $5 per barrel by 1993-1995 (Figure 27).

However, most of this drop occurred in the 1980's. During the first half of the 1990's, finding costs fell at about half the rate of their decline in the 1980's. Further, since 1995, finding costs have risen to a level which essentially erases the decline of the early 1990's. For the most recent 3-year period, 1995-1997 (compared to the previous 3-year period, 1994-1996), finding costs rose in the United States and abroad in all but two regions (the Other Eastern Hemisphere and the Former Soviet Union) (Table 24). Worldwide finding costs were up 13 percent between the two periods.

Figure 27. U.S. Onshore, U.S. Offshore, and Foreign Finding Costs (3-Year Moving Average) for FRS Companies, 1981-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 24. Finding Costs by Region, FRS Companies, 1994-1996 and 1995-1997
(Dollars per Barrel of Oil Equivalent)

Region	1994-1996	1995-1997	Percent Change
United States			
Onshore	3.98	4.37	9.8
Offshore	5.11	6.37	24.6
Total United States	4.39	5.07	15.7
Foreign			
Canada	5.62	6.88	22.4
OECD Europe	4.40	5.49	24.8
Former Soviet Union	8.46	6.93	-18.0
Africa	3.33	4.25	27.8
Middle East	2.11	2.20	4.3
Other Eastern Hemisphere	6.07	4.66	-23.2
Other Western Hemisphere	1.98	2.32	17.4
Total Foreign	4.12	4.53	10.1
Worldwide Total	4.24	4.79	12.9

Note: The above figures are 3-year weighted averages of exploration and development expenditures (current dollars), excluding expenditures for proved acreage, divided by reserve additions, excluding net purchases. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

In the United States, most of the 1995-1997 increase was experienced in offshore locales, where finding costs increased more than $1 per boe between the two periods (Table 24). Even with this increase, these offshore finding costs are still relatively low, more than 20 percent lower than their 1988-1990 level, and much lower than earlier periods. Nonetheless, it seems clear that finding costs have begun increasing in recent years.

A more detailed examination of finding costs in the United States provides more information about their most recent patterns. Figures 28 and 29 show annual finding costs and three-year weighted average finding costs, onshore and offshore, in the 1990's. On an annual basis, between 1995 and 1997, U.S. onshore finding costs were up by more than $2 per barrel (in 1997 dollars) and U.S. offshore finding costs were up nearly $3 per barrel.

A Closer Look Raises Concern Over Finding Rates

Further insight into the rise in finding costs can be gained by breaking them down into their components -- finding rates (a physical measure of the productivity of exploration and development drilling), drilling expenditures, and other exploration and development expenditures. (Conceptually, as with finding costs, finding rates are all the reserves that were added per well, no matter when they were recognized on a company's books, in drilling any particular set of exploratory and development wells, including dry holes. In practice, finding rates are measured as the ratio of reserve additions, excluding net purchases, to the total number of exploratory and development wells completed, including dry holes, during a particular period of time. The finding rates presented in this report, unless specified otherwise, are also calculated for periods of three years.)[b]

Finding costs can be expressed as the mathematical product of exploration and development expenditures per completed well times the inverse of finding rates. That is, finding costs = (expenditures/wells completed) x (wells drilled/reserve additions). Further, expenditures/wells completed = (drilling costs/wells completed) + (other expenditures/wells completed).

Table 25 shows the contributions of these various components to the percent rise in annual finding costs (in 1997 dollars) between 1995 and 1997 for the U.S. onshore and U.S. offshore locales. For the onshore, lower finding rates were far more important than increased expenditures per well, accounting for 63 percent of the rise in finding costs between 1995 and 1997. For the offshore it was more evenly split: 52 percent of the rise in finding costs can be attributed to reduced finding rates and 48 percent to increased expenditures per well.

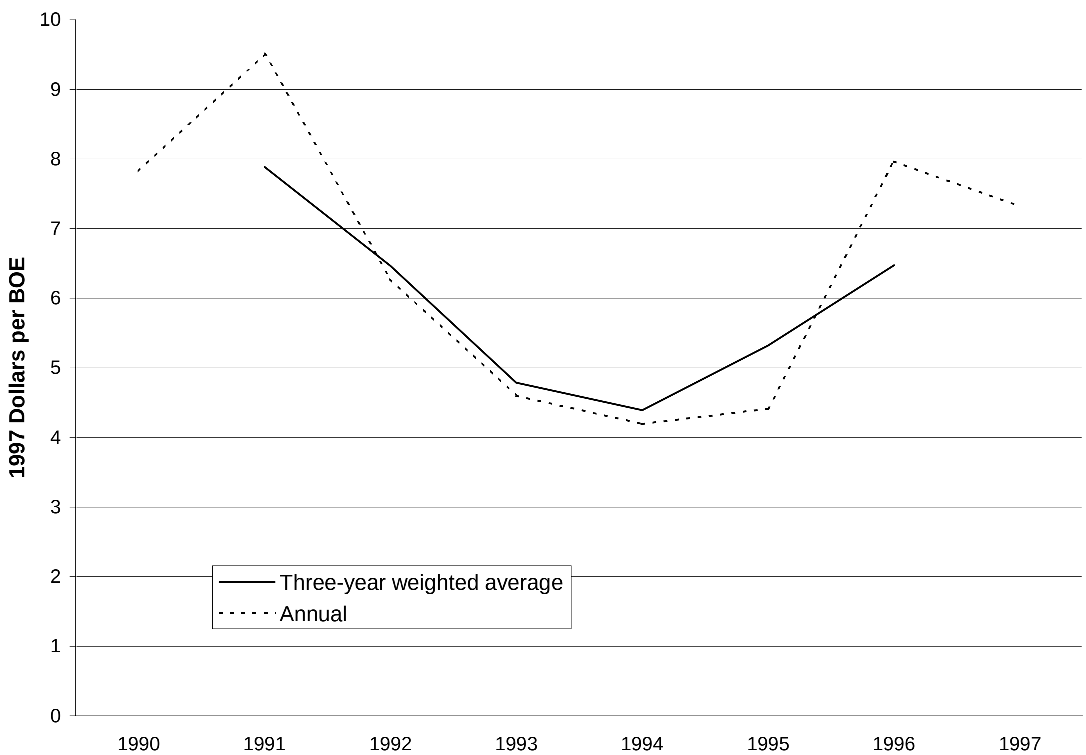
One possible cause of lower finding rates is diminished returns to drilling; another is that smaller reservoirs were found. This is the expected result of continued increases in drilling in the short run, as less and less promising areas are drilled within conventional depth limits. Increased expenditures per well can be the result of increased drilling, acreage acquisition, lease equipment, support equipment, and direct overhead costs. Drilling costs contributed about 45 percent to the increased expenditures per well onshore. Offshore, drilling costs accounted for 40 percent of the increase in total expenditures per well.

In sum, the breakdown of sources of increased finding costs between 1995 and 1997 onshore was: 63 percent due to diminishing returns (reduced finding rates), 17 percent due to increased drilling expenditures, and 20 percent due to expenditures for other exploration and development activities. Offshore, the respective shares were: 52 percent, 19 percent, and 29 percent.

Figure 28. Onshore Finding Costs for FRS Companies, 1990-1997

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 29. Offshore Finding Costs for FRS Companies, 1990-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 25. Analysis of Increase in Annual Finding Costs for FRS Companies, 1995-1997

	Onshore	Offshore
Finding Cost ($1997 per BOE)		
1995	3.52	4.41
1997	5.53	7.32
Share of Percent Change in Finding Costs due to:		
Lower finding rate	62.6	51.7
Increased expenditures per well	37.4	48.3
Total	100.0	100.0
Share of Increased Expenditures per Well due to:		
Increased drilling costs	44.9	39.6
Increase in other costs	55.1	60.4
Total	100.0	100.0

Note: BOE = Barrel of oil equivalent, natural gas is converted on the basis of 0.178 barrels of oil per thousand cubic feet of gas. Finding rate = Reserve additions (excludng net purchases of reserves) per well completed. Other costs include unproved acreage acquisition, exploration expenses, lease equipment, support equipment, work-in-progress, and direct overhead.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

While previous editions of *Performance Profiles* have noted a continuing drop in finding costs at a time of fast-accelerating use of new exploration and development technologies, a recent increase in these costs now seems clear. However, this reversal in the trend may be a temporary phenomenon, particularly if technological advances again begin to lower these costs over the long run.

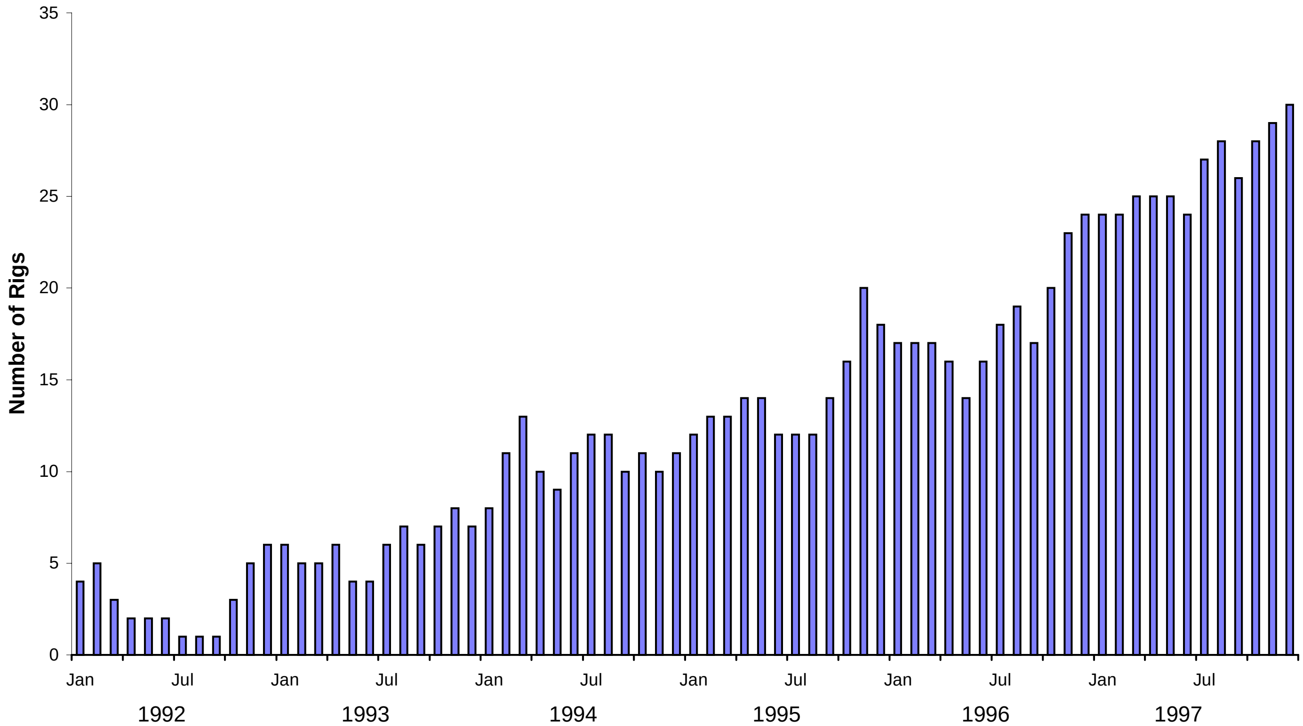
Are Seismic Advances Offshore Causing a "Bump In The Graph?"

In fact, the implementation of technological advances may be partially responsible for the upturn in finding costs. As new technologies are adopted, costs may rise temporarily as companies deal with the implementation learning curve. The rise in finding costs is most pronounced in the U.S. offshore, which is primarily in the Gulf of Mexico. As discussed in the following paragraphs, the Gulf has recently been an area of strong exploration and development activity, where new seismic technologies are being implemented in the search for new oil and gas reserves. The initial implementation of these technologies may have contributed to the decreased finding rates in this locale.

Less than a decade ago, the Gulf of Mexico was considered to be a mature area with limited potential for further exploration and development. At one point, some observers were so pessimistic on the region's prospects that they even referred to it as the "Dead Sea." More recently, the Gulf has undergone a renaissance of vast proportion.

In the deepwater region of the Gulf (defined here as those areas with a water depth greater than 1,000 feet), once believed to be only marginally economic, the number of active rigs has increased sharply over the 1992 to 1997 period (Figure 30). While the number of producing wells in the deepwater is less than 10 percent of the total number of producing wells in the Outer Continental Shelf (OCS), as of 1997, deepwater oil production accounted for 25 percent of total OCS production in the Gulf of Mexico (Figure 31). Because of infrastructure requirements, deepwater natural gas production is more modest, averaging only 7 percent of total Gulf of Mexico OCS production in 1997. According to the Minerals

Figure 30. Monthly Average Deepwater Rig Use Count in the Gulf of Mexico Outer Continental Shelf, January 1992-December 1997



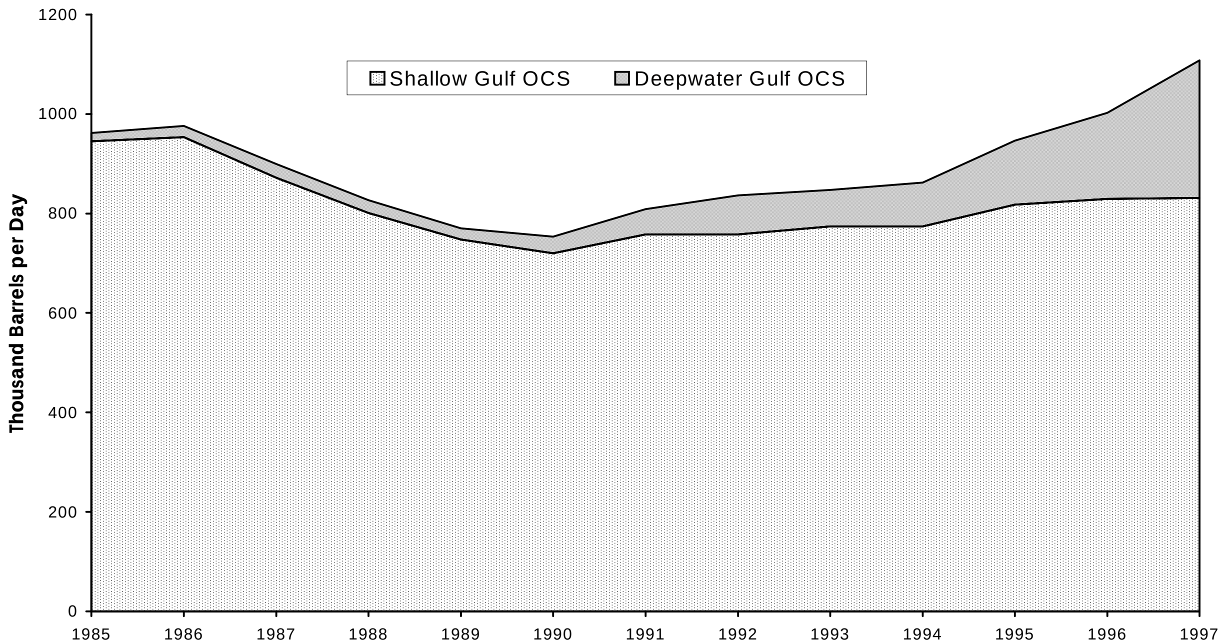
Note: Deepwater is a water depth greater than 1,000 feet.
Source: U.S. Department of the Interior, Minerals Management Service, http://www.mms.gov/ (December 2, 1998).

Management Service (MMS), deepwater fields will account for 56 to 64 percent and 23 to 30 percent of total oil and gas Gulf of Mexico OCS production, respectively, by the year 2000.[c]

Advances in seismic data acquisition and interpretation are widely regarded as one of the keys to the region's revival.[d] Through the use of this technology, the explorationist can construct a three-dimensional image of the subsurface before drilling and thus significantly increase the probability that the drilling prospects will yield sufficient reserves and production rates to warrant development. In addition to the deepwater region, the technology has been indispensable to exploration in the subsalt play of the Gulf. This region spans a vast area south of Louisiana totaling approximately 36,000 square miles that is characterized by tabular salt bodies or salt sheets. Prior to the development of 3-D seismic, the salt prevented explorationists from obtaining a detailed image of the subsalt geology. (Figure 32).

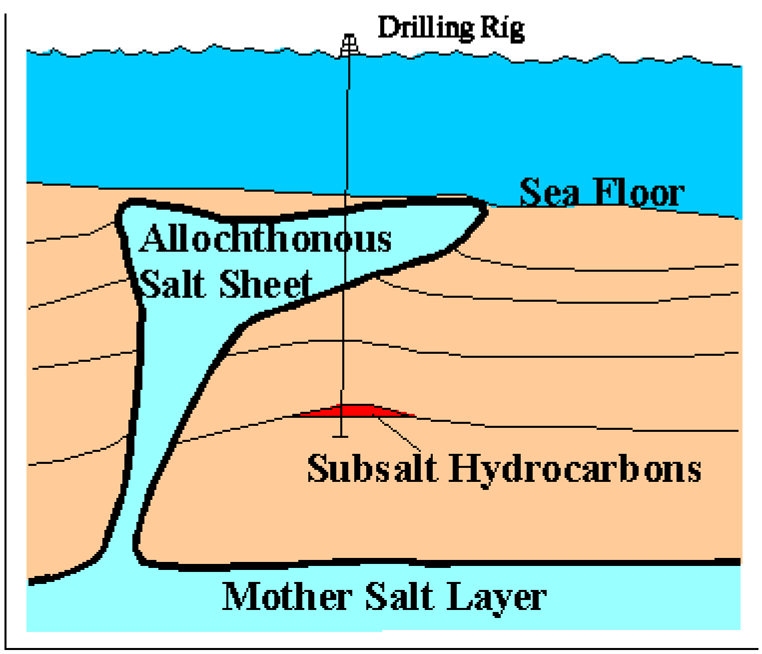
Geophysicists began to experiment with 3-dimensional (3-D) seismic in the 1970s. However, commercialization of the technology was inhibited by its data processing requirements. Prior to 1990, the computations associated with the processing of 3-D seismic data could tie-up the largest processors for weeks. Advances in satellite positioning, new processing algorithms, and more powerful workstations have dramatically reduced the amount of time required to collect and process the data. As a result of these and other advances in the technology, the percent of wells drilled in the Gulf where 3D technology has been employed increased from 5 percent in 1989 to 80 percent in 1996.[e]

Figure 31. Oil Production in the Gulf of Mexico Outer Continental Shelf, 1985-1997



Source: U.S. Department of the Interior, Minerals Management Service, http://www.mms.gov/ (December 2, 1998).

Figure 32. Image of Subsalt Geology



Source: U.S. Department of the Interior, Minerals Management Service, http://www.mms.gov/ (December 2, 1998).

In the long run, the application of 3-D seismology and other improvements in exploration technology are generally believed to have had a dramatic effect on the exploratory success rate in the offshore. Over the period 1985 through 1997, the offshore exploratory success rate for the FRS companies increased from 36 percent to 51 percent despite the fact that the price of oil, which tends to have a positive influence on the success rate, declined by 50 percent in real terms (Figure 33).[f]

[a]This estimate of finding costs is probably most useful as an indicator of trends in the cost of adding reserves since one inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not necessarily correspond exactly with each other. For example, the reserves added from a successful well drilled late in this year might not be recognized in a company's accounts until the following year, while the expenditures may be recognized this year. One way to moderate this limitation is to increase the length of the time period over which finding costs are measured, allowing reserve additions and exploration and development expenditures to match up more closely.

[b]As with finding costs, finding rates as measured are limited because the reserves added and the wells completed during a particular interval of time do not necessarily correspond exactly with each other. Again, this limitation is moderated by increasing the length of the time period for which finding rates are measured.

[c] U.S. Dept. of the Interior, Minerals Management Service, "Gulf of Mexico OCS Daily Oil and Gas Production Rate Projections from 1998 through 2002," MMS 98-0013, (February 1998).

[d.] Other important factors are the high productivity rates of the wells in the deepwater, and the recently enacted royalty relief for deepwater production as well as advances in production technologies such as the introduction of tension leg platforms.

[e] "U.S. E&P Surge Hinges on Technology, not Oil Prices," *Oil and Gas Journal*, 1997, p.42.

[f] For more discussion of the impact of 3-D seismic, see Douglas R. Bohi, "Changing productivity in the U.S. Petroleum Exploration and development," Resources for the Future, Discussion paper 98-38, June 1998. See also, Kevin Forbes and Ernest Zampelli, "Technology and the offshore Success Rate," United States Association for Energy Economics, 19th Annual North American Conference, (October 1998).

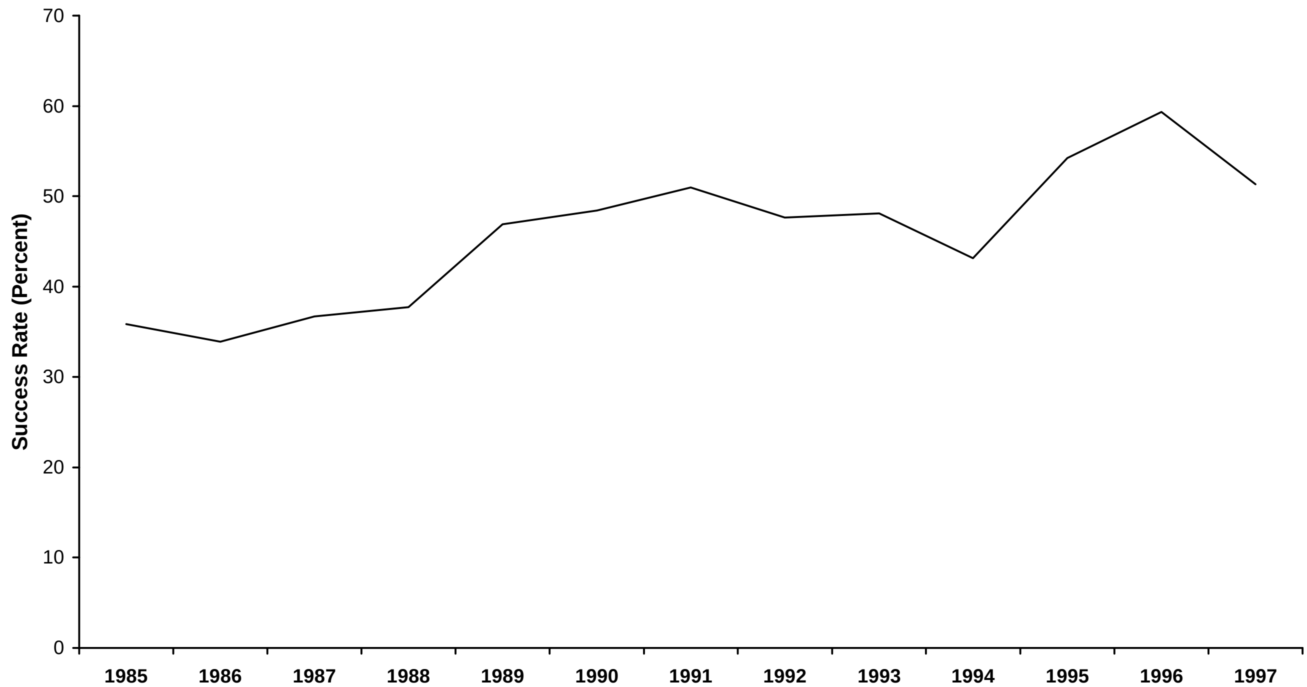
SPECIAL TOPIC: Venezuela Offers Full Market Value to Encourage Foreign Investment in Oil

In 1976, the government of Venezuela nationalized the Venezuelan assets of the FRS companies that had operations in that country. Given that the price of oil had recently doubled, there were few doubts that Petroleos de Venezuela S. A. (PDVSA), the state-owned enterprise charged with managing the nationalized properties, would continue to effectively develop the country's oil and gas resources. However, the decline in the price of oil after 1981 and the financial and technological requirements associated with upgrading Venezuela's declining productive capacity ultimately led Venezuela to reconsider its decision.

In 1989, the government began to develop a policy known as "Apertura Petroera" (or Petroleum Opening) that has encouraged foreign investment in its oil industry. The central goal of the policy change was to increase Venezuela's productive capacity through the rejuvenation of its existing fields, the development of its huge resources of extra-heavy crude oil, and the discovery of new fields of medium and light crude outside of the traditional producing regions.

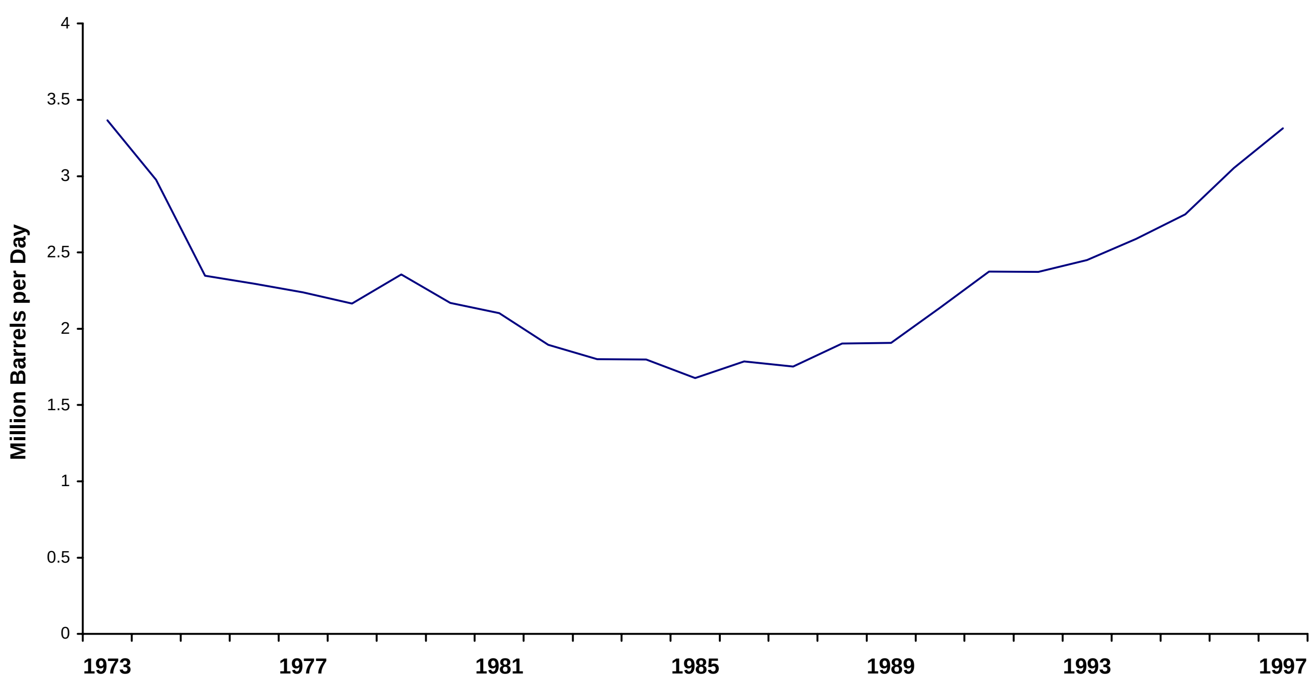
While the full impact of the policy change has yet to be realized, it is not too early to assess its effect to date. Between 1976 and 1989, production declined by 17 percent. Over the period 1990 and 1997, output increased by 55 percent to 3.3 million barrels per day (mb/d) (Figure 34). There can be little doubt that the Apertura Petroera contributed to this reversal in trend.

Figure 33. Offshore Exploratory Success Rate for the FRS Companies, 1985-1997



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 34. Crude Oil Production in Venezuela, 1973-1997



Source: Energy Information Administration, http://www.eia.doe.gov/pub/energy.overview/monthly.energy/mer10-1a (December 2, 1998).

The first phase of the policy change opened up the operation of inactive or abandoned fields to the private sector. Between 1992 and 1993, a total of 14 contracts were awarded (in the 1st and 2nd Reactiviation Round auctions). Under these contracts, the operator received a 20-year contract that mandated certain minimum investment levels. In return, the operator received a fee for each barrel produced.

The potential for these projects was originally estimated to be 125,000 b/d; as of 1997, however, they were already producing 260,000 b/d, more than twice the original estimate.[a] According to one source, these fields can now be expected to produce 500,000 b/d within a few years.[b] These increases can be attributed to PDVSA's relative inexperience in managing smaller mature fields, as well as its isolation from the recent technological advances in the industry that have made it possible to sustain (and some cases even increase) production from seemingly mature producing properties.

In 1997, Venezuela completed its 3rd Reactivation Round by auctioning off 20 additional marginal oil fields. In contrast to the earlier auction rounds, the operators are now entitled to receive the full market value of additional output (net of a one-sixth royalty and administrative costs) until their investment is recovered. Subsequent to the recovery of initial costs, operators are then entitled to a percentage of net incremental value above costs with the percentage rising as the field matures.

The government earned about $2 billion in bid revenue from the round, about twice as much as had been expected. Moreover, the new operators have indicated that they expect to boost production from the fields from 150,000 barrels per day (b/d) to 500,000 b/d. Two cases where the increases in expected production are especially striking include:

- **The LL-652 Field**. A consortium headed by Chevron submitted the winning bid of $251 million. Under the former management, the field produced 12,000 b/d of light crude. Chevron and its partners (Statoil, 30 percent; Phillips Petroleum, 20 percent; and ARCO, 20 percent) believe they can boost production to 100,000 b/d. The partners in the project anticipate investing $400 million in rejuvenating this field.

- **Preussag Energie.** The winning companies have indicated that they expect to increase production from 8,500 b/d presently to 150,000 b/d within 3 to 5 years.

The future trend in Venezuelan production is largely dependent on the success of a number of recently authorized joint ventures (listed below) to upgrade the extra-heavy crude resources in the 270-mile long by 40-mile wide Orinoco Belt in eastern Venezuela. This region is believed by some to have reserves that rival any other country. Petroleos de Venezuela, S.A. has estimated that there are 270 billion barrels of recoverable reserves in the area.[c]

There are currently four heavy crude projects in this area, at various stages of development. However, startup dates for Cerro Negro, Sincor, and the Petrolera Ameriven ventures have been pushed back by up to eight months due to the impact of the 1998 plunge in oil prices on PDVSA's ability to provide its share of the funding. In addition, three other projects have been planned but have not yet received government approval. Upon completion, these projects are expected to add 500,000 to 700,000 b/d to Venezuela's productive capacity.

- **Petrozuata**. Production from this joint venture between Conoco (50.1%) and PDVSA (49.9%) commenced in September 1998. Work on the 55,000-acre tract began in 1997 with the drilling of approximately 75 horizontal wells. Initial production was approximately 30,000 b/d but is scheduled to rise to 120,000 b/d as more wells are drilled. Approximately 500 horizontal wells are scheduled to be drilled. Beginning in 2000, the crude will be transported 200 kilometers to the coastal city of José where it will be processed into synthetic crude oil. (Until 2000, the crude will be mixed with a lighter crude and marketed.) The crude is so heavy (9° API) that it must be diluted in order for the oil to flow through the pipeline. The upgrading process is expected to convert the crude into a 19° to 25° API synthetic light oil. The cost of the project (including the cost of the upgrading unit) is $2.45 billion.

- **Sincor.** This project is believed to have 2.4 to 3.6 billion barrels of recoverable reserves. The crude has an API gravity rating of 8.5°. Development costs are approximately $4.3 to $4.6 billion. Partners in the project are Total (47%), Statoil (15%), and PDVSA (38%). The project entails the drilling of 1,200 wells, of which approximately 900 are expected to be horizontal wells. Production of approximately 175,000 barrels of 32° synthetic crude per day is expected. Limited production was scheduled to startup in 2000, with full production being acheived in 2002

- **Cerra Negro.** The partners in the project are PDVSA (41.67%), Mobil (41.67%), and Veba Oel (16.66%). The plan was to produce, upgrade, and market 120,000 bpd (60,000 by late 1999) of extra-heavy crude (8.5° API gravity rating), although this will probably be delayed by PDVSA's budget cuts. However, indicative that the project is going forward, the joint venture recently awarded a $500-million contract to build an upgrading plant. Approximately 350 wells are expected to be drilled. The expected cost of the project is $2.5 billion with about $1.9 billion of this being spent on the upstream portion.

- **Petrolera Ameriven**. This consortium includes Texaco (20%), ARCO (30%), Phillips Petroleum (20%), and PDVSA (30%). It is expected that 700 to 1,300 horizontal wells will be drilled over a 35-year period. The project will take 9° API gravity crude oil and upgrade it to a 27.5° API gravity synthetic crude. Plans called for production beginning in early 1999 at 36,000 b/d with production rising to 157,000 b/d by 2003. Estimated development costs are $3.6 billion.

In 1996, the Venezuelan Congress authorized profit sharing agreements (PSAs) under which private firms have the right to explore and develop new areas. Under the PSAs, the foreign companies bear all exploration costs, with a maximum nine-year exploration period (during which the company is obligated to spend a minimum of $40 to $60 million per block). If a commercial deposit is discovered, a joint venture with PDVSA is formed (with PDVSA having up to 35 percent of the equity) to exploit the discovery. A foreign company's total tax burden under a PSA can range between 85% and 94%. Despite these seemingly prohibitive terms, over 75 companies participated in the auction. Five international joint ventures and three solo firms won the right to develop eight blocks, located throughout Venezuela. Exploration and development of these areas could increase productive capacity by 500,000 b/d. These ventures include:

- **Quiamare - La Ceiba.** Interest in this block is shared by Mobil, Repsol S.A., Sipetoal S.A., and Tecpetrol S.A. In early 1998, the joint venture reported a discovery well with a flow of 16,000 b/d.

- **Gulf of Paria.** Conoco was awarded 100 percent interest in a mostly offshore block in the waters between Venezuela and Trindad.

- **Guanare.** This block is located in the foothills of the Merida Andes in the western part of the country. Conoco and Elf Aquitaine have equal interests in the venture.

[a] Mommer, Benard, *The New Goverence of Venezuelan Oil*, Oxford Institute for Energy Studies, 1998, p. 48.

[b] Mommer, Benard, *The New Goverence of Venezuelan Oil*, Oxford Institute for Energy Studies, 1998, p. 48.

[c] L.R. Aalund, "Technology, Money Unlocking Vast Orinoco Reserves," *Oil and Gas Journal* (October 19, 1998, pp. 49-50).

5. Foreign Investment in U.S. Energy

Foreign Acquisitions and Divestitures of U.S. Energy Assets

Drop in Acquisitions Masks Continued Foreign Interest in U.S. Oil and Gas

The attractiveness of U.S. energy as a target of foreign investors appeared to diminish in 1996, despite steep gains in the profitability of petroleum and natural gas operations. In 1996, acquisitions that affected the foreign direct investment position ("FDI-related" acquisitions) in U.S. petroleum (including natural gas) and coal totaled $1.9 billion in value, down from $3.3 billion in 1995 and well below the annual average of $2.7 billion during the 1990's (Table 26 and Figure 35). Nevertheless, despite the decline in acquisition activity, a number of notable developments in foreign investors' interest in U.S. oil and gas and U.S. energy in general were apparent in 1996:

- The largest FDI-related acquisition ($1.2 billion) involved midstream natural gas assets (midstream natural gas activities include transmission, distribution, and marketing) which, for the purposes of this report, is a new classification of energy investment.

- Acquisitions of upstream oil and gas assets fell to $368 million, about 90 percent below the prior year's level. However, this reduced level of acquisitions mainly reflected cutbacks in purchases of producing properties due to steep rises in their price following the upswing in oil and gas prices in 1996. As discussed in a later section, total spending by foreign affiliates for U.S. exploration and development increased 42 percent between 1994 and 1996, indicating a strong interest in U.S. oil and gas production.

- The value of transactions involving divestitures of U.S. energy assets by foreign investors totaled $1.5 billion in 1996, the second highest level in the 1990's.

- Foreign-affiliated companies choosing not to divest their U.S. energy operations have expanded these operations through internal investment. Thus, despite the increased level of FDI divestitures and the decreased level of FDI acquisitions, foreign-affiliated companies' shares of U.S. energy operations generally held steady between 1995 and 1996.

Midstream Natural Gas Was the Main Attraction

The largest FDI-related transaction in 1996 was a cash-and-stock deal valued at $1.2 billion in which NGC Corporation acquired Chevron's natural gas marketing business and Warren Petroleum, their natural gas liquids company (see the Highlight entitled, "Major FDI-Related Transactions in U.S. Energy 1996"). NGC became a foreign-affiliated company in 1994 when Nova Corporation, a Canadian company, and British Gas, p.l.c. gained a 37-percent ownership interest. NGC's presence in U.S. energy grew in 1995 through a merger with Trident NGL Holdings, a natural gas liquids producer, valued at $167 million, and their purchase of Ozark Gas Transmission System for $45 million.

Table 26. Value of FDI-Related Transactions in U.S. Energy, 1990-1996
(Million Dollars)

Acquisitions/Divestitures	1990	1991	1992	1993	1994	1995	1996
Acquisitions							
Oil and Gas Production[a]	901	1,043	949	1,246	159	2,570	368
Midstream Natural Gas	NA	NA	NA	NA	170	367	1,252
Petroleum, Refining, and Marketing	1,040	103	173	1,264	0	339	50
Coal	1,416	570	1,276	1,928	674	0	204
Other Energy	0	0	0	150	0	0	0
Total Acquisitions	3,357	1,716	2,398	4,588	1,013	3,276	1,874
Divestitures							
Oil and Gas Production[a]	474	736	461	938	663	699	660
Midstream Natural Gas	NA	NA	NA	NA	0	167	123
Petroleum, Refining, and Marketing	59	400	60	822	41	0	679
Coal[b]	841	155	869	438	768	110	0
Total Divestitures	1,374	1,291	1,390	2,198	1,472	976	1,462

[a] Includes drilling and drilling services.

[b] 1990 includes Newmont Mining's sale of its 55-percent interest in Peabody Holding Company for $726 million, while 1992 includes Shell Oil's divestiture of its coal operations for $850 million.

NA=Not available.

Note: 1995 divestitures do not include DuPont's $8.8-billion stock buyback.

Sources: **1996:** Based on Tables C1 and C2 in Appendix C. **1994-1995:** Tables C1 and C2 in Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998), and preceding issues. **1990-1993:** Tables A1 and A2 (and, for 1993, Table A3) in Energy Information Administration, *Profiles of Foreign Direct Investment 1993*, DOE/EIA-0466(93) (Washington, DC, May 1995).

Figure 35. Value of FDI-Related Acquisitions in U.S. Energy, 1981-1996

Source: **1996**: Tables C1 and C2 in Appendix C. **1981-1995**: Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998), Tables C1 and C2, and previous editions.

HIGHLIGHT: Major FDI-Related Transactions in U.S. Energy 1996

Acquisitions

NGC Corp., majority owned by British and Canadian interests, acquired Chevron's natural gas marketing business and natural liquids company, Warren Petroleum, in a cash-and-stock deal valued at $1.2 billion.

Japan's ITOCHU Corp., an investment company, and Atlantic Richfield Co., jointly paid $615 million for Coastal Corporation's western coal operations, including its Utah mines. ITOCHU's share was $204 million.

Swedish affiliated Forcenergy Gas Exploration Inc. purchased an unspecified interest in a Prudhoe Bay property for $97.8 million from Marathon Oil.

The Alabama refinery of Louisiana Land & Exploration Co. was acquired by Shell Chemical Company for a reported price of $50 million. Shell Chemical is a unit of Shell Oil Co., subsidiary of the Royal Dutch/Shell Group.

In a transaction between two foreign affiliates, CXY Energy Offshore, subsidiary of Canadian Occidental Petroleum, paid Royal Dutch/Shell's unit Shell Offshore Inc. $50.2 million for a 100-percent interest in certain Louisiana properties.

Divestitures

Arethusa Offshore Ltd, a U.S.- based unit of Belgium's CMB NV, was sold to Diamond Offshore Drilling Inc. for $561 million.

Circle K Corporation, with approximately 2,300 convenience stores (most of which sell gasoline), was sold to Tosco Corporation for $444 million. Circle K was previously owned by Bahraini-owned Invest Corp, S.A.

British Petroleum sold its northeast U.S. refining and marketing business to Tosco Corp. for a reported $235 million. The divested assets include a refinery, product terminals, and pipeline interests in five states.

Norcen Energy Resources, Canada, received $106 million from a private sale of its U.S. subsidiary, Skelgas Propane Inc.

Royal Dutch/Shell's unit, Shell Offshore Inc., received $50.2 million from CXY Energy Offshore for a 100-percent interest in certain Louisiana properties.

The latest NGC acquisition reflects the growth of natural gas marketing in the United States in recent years, along with the services of natural gas brokers and providers of transportation services. This growth followed the implementation of Federal Regulatory Commission (FERC) Order 636, which required unbundled provision of natural gas sales and natural gas transport and the deregulation of natural gas production. Also contributing to the growth in midstream natural gas investment is the continued integration of U.S. and Canadian natural gas markets. Over the 1987-1996 decade, imports from Canada grew from 6 percent of U.S. natural gas consumption to 13 percent.

Also of note is that the 1995 NGC merger with Trident NGL Holdings brought electricity generation and marketing businesses into NGC's asset base (as did NGC's acquisition of DESTEC in 1997). Prior to this 1995 merger, foreign ownership of U.S. electric utilities has been nonexistent. The most important reason for this lack of ownership is that foreign entities cannot own U.S. nuclear energy facilities, a restriction that puts many domestic electric utilities out of reach. Also, the myriad of state laws and regulations and Federal regulations directed toward electricity generation, transmission, and distribution, as well as prescribed rates of return, collectively form a practical barrier to foreign acquisitions of U.S. electric utilities. However, as states deregulate their electricity sectors and require separation of generation, transmission, and distribution, impediments to foreign ownership in U.S. electricity will be reduced. At the same time, much of the electricity sector may be in considerable flux as transitions to as-yet-unknown ownership structures are effected.

In this economic climate, investors with experience in already-deregulated electricity sectors abroad might be comparatively advantaged. It can thus be anticipated that foreign investors will acquire U.S. electricity assets as deregulation proceeds.

Foreign Affiliates' U.S. Exploration and Development Expenditures Continue to Rise

As gauged by expenditures for exploration and development, foreign affiliates continued to be attracted to U.S. oil and gas in 1996. Expenditures were up $0.4 billion from 1995 to 1996, to $4.9 billion, following a $1.0-billion rise in the prior year (Table 27). The increases in spending were widespread as most companies reported higher expenditures. Shell Oil registered the largest increase, which mainly reflected their ever-growing commitment to deepwater drilling. In Shell Oil's words,

> "The substantial increase in 1996 over both 1995 and 1994 was due to higher spending for production drilling and development in the Gulf of Mexico and for gas pipeline facilities to accommodate deepwater production. The higher level of capital spending is expected to continue through the decade as Shell Oil develops the Gulf of Mexico projects."[76]

The most recent data from the Minerals Management Service indicate that foreign affiliates' interest in the Federal Outer Continental Shelf (OCS) is generally growing. Excluding Conoco (which was foreign-affiliated in 1994 but not in 1995), foreign affiliates' share of OCS oil production increased to 27 percent and their share of OCS natural gas production increased to 17 percent between 1994 and 1995 (Table 28).

The only notable divestiture in upstream U.S. oil and gas was the sale by Belgium's CMB NV of its U.S.-based Arethusa Offshore Ltd., an offshore oil field services company, to Diamond Offshore Drilling in a transaction valued at $561 million.

Table 27. U.S. Capital and Exploratory Expenditures of Foreign-Affiliated Petroleum and Natural Gas Companies, 1994-1996
(Million Dollars)

Company	Upstream[a] 1994	Upstream[a] 1995	Upstream[a] 1996	Company	Downstream[b] 1994	Downstream[b] 1995	Downstream[b] 1996
Shell Oil	1,296	1,642	2,380	Shell Oil	1,087	1,065	726
BP America	826	875	972	PDV America[c]	490	540	580
DuPont	357	NF	NF	BP America	226	210	195
Forcenergy	57	144	283	Castle Energy	218	NF	NF
Anadarko Petroleum	352	225	265	DuPont	191	NF	NF
Santa Fe Energy Resources	107	186	207	Star Enterprise	152	148	96
Louis Dreyfus Natural Gas	109	185	134	Fina	49	42	72
BHP Petroleum (Americas)	67	140	121	Total Petroleum, Ltd.	108	74	53
Canadian Occidental	47	95	118	Clark USA	100	42	45
Fina	64	83	105				
Norcen Energy Resources	43	48	97				
YPF	NF	647	68				
Chieftan Development International	22	87	56				
Cairn Energy USA	29	46	49				
Presidio Oil	35	18	NF				
Total	**3,411**	**4,421**	**4,855**	**Total**	**2,621**	**2,803**	**1,767**

[a]Oil and gas exploration, development, and production.

[b]Petroleum refining, marketing, and pipelines.

[c]Includes capital expenditures for Citgo Petroleum, additions to investments in Lyondell-Citgo Refining Co., and miscellaneous additions to investments in downstream subsidiaries, including Uno-Ven.

NF= Not foreign-affiliated in the year shown.

Sources: Company annual reports.

Table 28. Foreign Affiliates' Share of Gulf of Mexico Oil and Gas Production, 1987, 1994, and 1995
(Percent)

	1987	1994	1995
Crude Oil Production[a,b]			
Number of Foreign-Affiliated Producers	9	23	23
Foreign Affiliates' Share	25.0	30.4	26.6
Excluding Conoco	--	25.5	26.6
Natural Gas Production[a,c]			
Number of Foreign-Affiliated Producers	10	24	25
Foreign Affilates' Share	19.6	17.1	16.6
Excluding Conoco	--	13.7	16.6

[a]Operated basis.
[b]Includes condensate.
[c]Includes casing-head gas.
Source: Rolando A. Gächter, *Federal Offshore Statistics: 1995* (Herdon, VA: Minerals Management Service, U.S. Department of the Interior, 1997), and preceding issues.

Divestitures Dominate Downstream Petroleum

The second largest 1996 divestiture involving foreign affiliates, at $444 million, was the sale of Circle K Corporation to Tosco Corporation. Circle K, formerly owned by Bahraini-owned Investcorp S.A., has approximately 2,300 convenience stores of which 1,900 sell gasoline. Tosco also played a further role in FDI-related divestitures in 1996. BP America, the U.S. subsidiary of British Petroleum, sold its northeast refining and marketing assets to Tosco for $235 million. The primary asset was a 172,000-barrels-per-day refinery near Philadelphia.

Foreign-affiliated refiners, as well as the U.S. refining industry generally, continued to cut back on capital expenditures in 1996. Capital expenditures for U.S. refining, marketing, and transport of foreign-affiliated refiners totaled $1.8 billion, down 37 percent from 1995 spending (Table 27). Reduced expenditures largely reflected the completion of environmentally-related projects stemming from requirements of the Clean Air Act Amendments of 1990 and additionally stringent air quality standards in California. Shell Oil, who reported the largest reduction in downstream capital expenditures, stated

> "Capital expenditures in 1996 [for oil products] of $726 million declined $339 million from 1995 .... Spending in 1995 ... was mainly for the coker and 'clean fuels' project at the Martinez, California refinery, completed in 1996 .... and ... environmental capital expenditures in 1996 were ... about $155 million below 1995, due mainly to completion of expenditures to comply with clean fuel requirements, primarily in California." [77]

Japanese Investors Make Noticeable Entry into U.S. Coal Production

The second-largest FDI-related energy acquisition involved the gain of an interest in Western coal production by the Japanese conglomerate, ITOCHU Corporation. An investment company formed by ITOCHU and Atlantic Richfield acquired Coastal Corporation's Utah coal operations for $615 million in 1996, of which ITOCHU's share was $204 million. As a result of this acquisition, ITOCHU has a 35-percent interest in Canyon Fuel Company, the largest coal producer in Utah, accounting for 1 percent of total U.S. coal production.

Foreign Direct Investment: Official Estimates

The foreign direct investment position (FDI) position is the cumulative net flow of funds between foreign-affiliated U.S.-based companies and their foreign owners. The U.S. Department of Commerce measures FDI as the book value of foreign direct investors' equity in and net outstanding loans to their U.S. affiliates. Examination of overall FDI provides an indication of the attraction of the U.S. economy as a target of foreign investors.

Attraction of the U.S. Economy Continued in 1996

Additions to the FDI position increased again in 1996, to $69.2 billion, up from $64.3 billion in 1995 (Table 29). Additions to the FDI position have generally increased since the recession-riddled year of 1991 when additions fell to $4.0 billion, a 20-year low. According to the U.S. Department of Commerce, "... the increase in the position in 1996 was mainly due to the continued strength of the U.S. economy, which attracted new investments from abroad and which expanded the earnings existing U.S. affiliates could draw on to finance growth. In addition, continued economic expansion in certain major investor countries, such as the United Kingdom and Japan, may have increased the ability of parent companies in those countries to make new acquisitions and to contribute additional capital to their existing U.S. affiliates and may have reduced their need to draw funds from their affiliates."[78]

Table 29. Geographic Sources of Foreign Direct Investment in U.S. Industry, 1994-1996
(Billion Dollars)

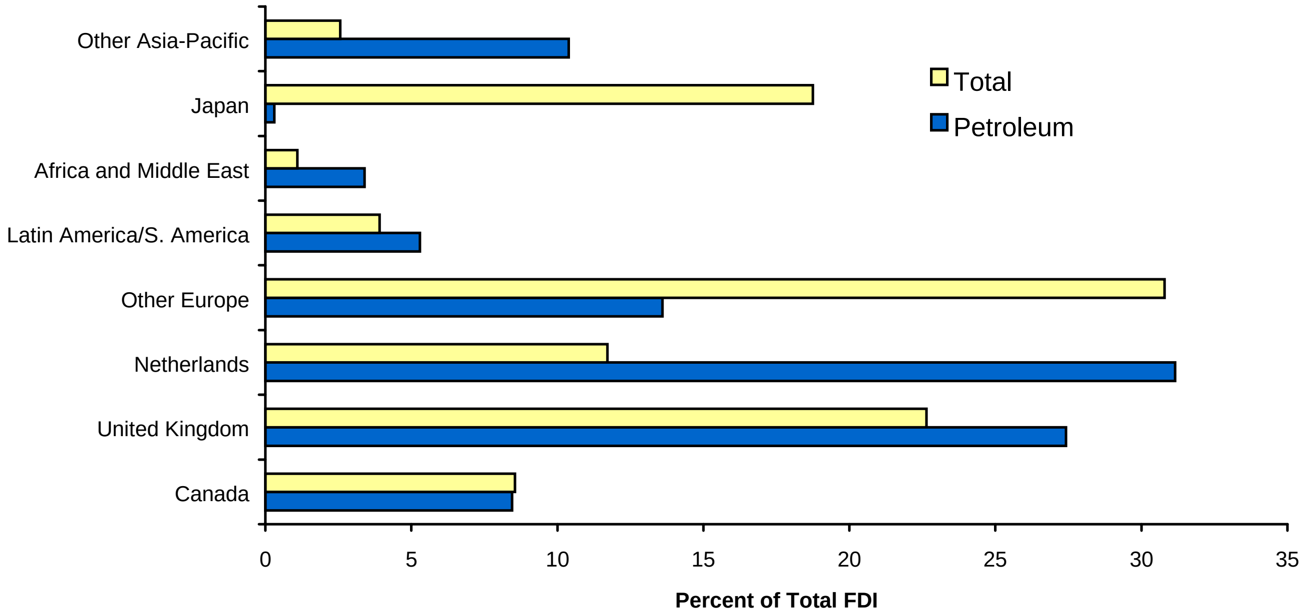
Region	Foreign Direct Investment Position			Net Additions	
	1994	1995	1996	1995	1996
All Countries	496.5	560.9	630.0	64.3	69.2
Canada	42.0	48.3	53.8	6.3	5.6
Europe					
United Kingdom	104.9	126.2	142.6	21.3	16.4
Netherlands	67.2	65.8	73.8	-1.4	8.0
Germany	40.3	49.3	62.2	8.9	13.0
France	33.6	38.5	49.3	4.9	10.8
Switzerland	26.7	35.6	35.1	8.9	-0.5
Other Europe	31.0	41.9	47.4	10.9	5.5
Latin America[a]					
Netherlands Antilles	9.2	8.5	9.1	-0.7	0.6
Panama	4.3	4.7	5.6	0.5	0.8
Venezuela	-0.3	-0.3	-0.0	0.1	0.2
Other Latin America	13.0	12.3	10.0	-0.7	-2.3
Australia	8.1	7.8	9.7	-0.2	1.9
Other OPEC[b]	4.6	4.0	4.2	-0.6	0.3
Japan	103.0	107.9	118.1	4.9	10.2
Other Countries	9.1	10.4	9.0	1.2	-1.4

[a]Latin America includes South America, Central America, and the Caribbean (outside of U.S. possessions and territories).
[b]Excludes Venezuela. OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Gabon, Indonesia, Iraq, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Note: Sum of components may not equal total due to independent rounding.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1997).

Regionally, European investors account for the largest share (almost two-thirds) of overall foreign direct investment in the United States in 1996 (Figure 36). On an individual country basis, however, investors in the United Kingdom ranked first in FDI position in the United States in 1996, with a 23-percent share, with Japanese investors second at 19 percent (Figure 36). Rounding out the top five countries were the Netherlands (12 percent), Germany (10 percent), and France (8 percent).

The pattern of FDI in U.S. petroleum (including natural gas) across countries is much more concentrated than overall FDI. Investors in the Netherlands and United Kingdom in 1996 accounted for 31 percent and 27 percent of FDI in U.S. petroleum, respectively (Table 29). This concentration reflects the large presence of Shell Oil, a subsidiary of the Netherlands' Royal Dutch/Shell Group, and BP America, a subsidiary of the United Kingdom's British Petroleum. In contrast to their prominence in overall FDI, Japan accounted for less than 1 percent of FDI in U.S. petroleum.

Figure 36. Geographic Shares of FDI for Petroleum and All U.S. Industries, 1996



Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Wahington, DC, September 1997)

Trend in Petroleum's Share of FDI Reverses

In 1996, the petroleum industry's share of overall FDI increased for the first time since 1987 (Table 30). Additions to FDI in petroleum were up sharply from $1.6 billion in 1995 to $8.5 billion in 1996 (Table 31). This development appears inconsistent with the sizable falloff in the value of FDI-related acquisitions in 1996 (Table 26). Several factors, however, may explain this apparent inconsistency. The disparity can in large part be attributed to foreign affiliates' already noted recent preference for growth via exploration and development activity rather than acquisitions. In 1996, petroleum and natural gas earnings were up considerably from recent years' levels, providing both an incentive to invest in oil and gas resource development and added investment capability in the form of increased cash flow. For foreign affiliates whose primary business activities are based in U.S. petroleum and natural gas, overall earnings were up 45 percent between 1995 and 1996, of which 67 percent was reinvested.[79]

Another factor contributing to the apparent disparity lies in an uncharacteristic set of FDI-related transactions. The first of these was a petroleum-based foreign affiliate's large acquisition of a company not in the petroleum business. In January, 1996, Australian-based BHP, whose U.S. subsidiaries were then primarily engaged in petroleum, acquired U.S.-based Magma Copper Company for $1.6 billion.[80] The value of this transaction equals the $1.6-billion increase in the petroleum FDI position for the "Asia and Pacific" region, of which Australia is a part (the U.S. Department of Commerce did not separately report Australia's FDI position in petroleum in 1996 due to disclosure policy) (Table 31). (It is not clear whether the U.S. subsidiaries of BHP (subsequent to this large acquisition) will continue in the future to be classified by the Commerce Department as a petroleum-based or a mining-based foreign affiliate.)

The second somewhat uncharacteristic source of disparity was $2.6 billion of additions to FDI in petroleum emanating from European countries outside the Netherlands and the United Kingdom in 1996, up from $0.2 billion in 1995. This large increase appears to be related to additions to investments in existing U.S. petroleum subsidiaries by German companies (Germany's FDI position in petroleum in 1996 was not separately reported by

Table 30. Foreign Direct Investment in U.S. Petroleum and Coal, 1980-1996
(Billion Dollars)

	Foreign Direct Investment in U.S. Petroleum[a,b]	Foreign Direct Investment in U.S. Coal	Total Foreign Direct Investment in the U.S.[a]	Petroleum as a Percent of Total	Coal as a Percent of Total
1980	12.2	0.5	83.0	14.7	0.6
1981	15.2	1.1	108.7	14.0	1.0
1982	17.7	1.2	124.7	14.2	1.0
1983	18.2	1.3	137.1	13.3	0.9
1984	25.4	2.6	164.6	15.4	1.6
1985	28.3	2.9	184.6	15.3	1.6
1986	29.1	3.5	220.4	13.2	1.6
1987	37.8	3.3	263.4	14.4	1.3
1988	36.0	5.3	314.8	11.4	1.7
1989	40.3	0.9	368.9	10.9	0.2
1990	42.9	0.8	394.9	10.9	0.2
1991	40.1	1.4	419.1	9.6	0.3
1992	34.7	1.0	423.1	8.2	0.2
1993	32.2	0.9	467.4	6.9	0.2
1994	32.3	0.6	496.5	6.5	0.1
1995	33.9	0.6	560.9	6.0	0.1
1996	42.3	0.8	630.0	6.7	0.1

[a]Foreign direct investment (FDI) is the value of foreign parents' net equity in, and outstanding loans to, affiliates in the United States at the end of the year.

[b]The petroleum industry includes all phases of oil and gas exploration and production, petroleum refining, petroleum transport, and petroleum marketing.

Sources: **1992-1996**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1997). **1991**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1996). **1987-1990**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1993). **1985-1986**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1990). **1981-1984**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1986). **1980**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, October 1984).

the U.S. Department of Commerce due to disclosure policy). According to the U.S. Department of Commerce, "... the increase in the position of German parents was more than accounted for by equity capital inflows, which were the largest from any country. The largest equity capital inflows were in services, insurance, petroleum, and 'other industries'. In insurance and services, the equity capital inflows reflected acquisitions; in petroleum and 'other industries,' they reflected capital contributions to existing affiliates."[81]

Foreign-Affiliated Companies' Role in U.S. Primary Energy Operations

The participation of foreign affiliates in the U.S. energy industry was little changed in 1996 (Figure 37) because the value of FDI-related acquisitions and divestitures in U.S. petroleum in 1996 were relatively small that year. The most notable trend was the continuation of the recent decline in foreign affiliates' share of U.S. refining capacity. While foreign affiliates' share of refining capacity grew in every year but one from 1984 through 1993, it declined in each of the next three years. In natural gas production, the share of foreign affiliates grew slightly, reversing part of last year's decline. Foreign affiliates' shares of oil and coal production were essentially unchanged in 1996.

Table 31. Geographic Sources of Foreign Direct Investment in U.S. Petroleum, 1994-1996
(Million Dollars)

Source	Foreign Direct Investment Position			Net Additions	
	1994	1995	1996	1995	1996
All Countries	32,290	33,888	42,343	1,598	8,455
Canada	3,097	3,220	3,577	123	357
Europe					
United Kingdom	9,489	9,696	11,610	207	1,914
Netherlands	11,444	11,666	13,191	222	1,525
Germany	111	(b)	(b)	(b)	(b)
Other Europe	2,903	(b)	(b)	(b)	(b)
Total Europe	23,947	24,527	30,560	580	6,033
Latin America[a]					
Venezuela	-570	-513	-331	57	182
Other Latin America	1,624	2,478	2,572	854	94
Australia	2,965	3,333	(b)	368	(b)
Other OPEC[b]	1,579	1,233	1,393	-346	160
Japan	147	83	128	-64	45
Other Countries	-499	-473	(b)	26	(b)

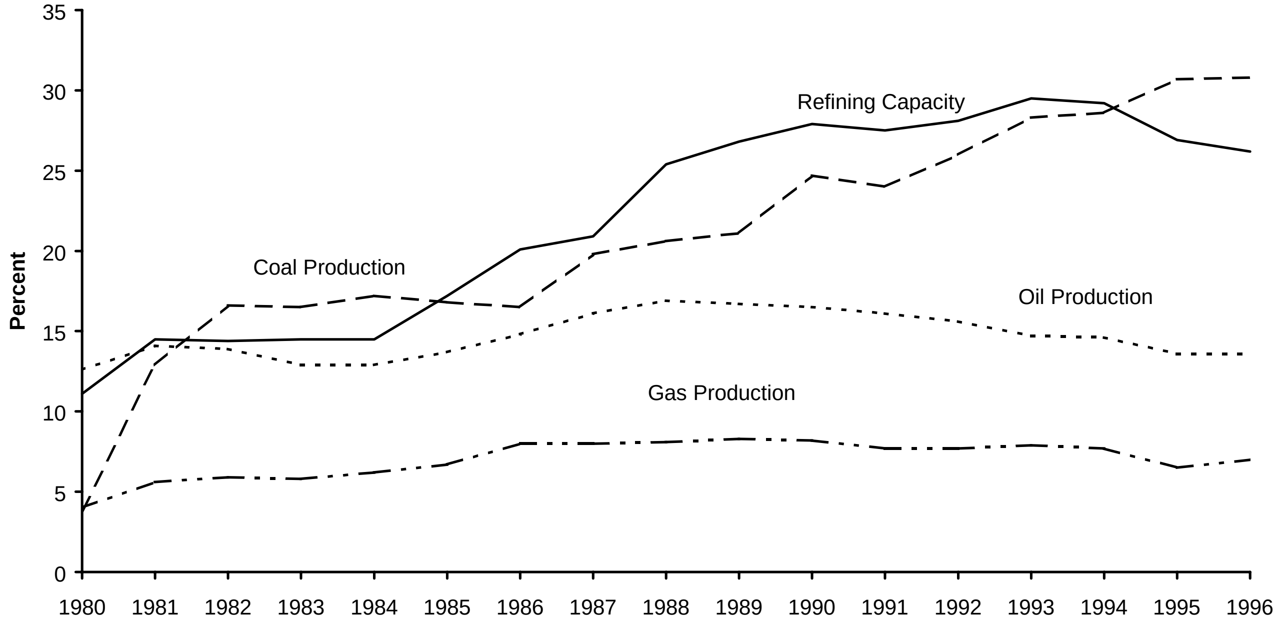
[a]Latin America includes South America, Central America, and the Caribbean (outside of U.S. possessions and territories).
[b]Data withheld by the U.S. Department of Commerce to prevent disclosure of data of individual companies.
[c]Venezuela is not included. OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Ecuador, Gabon, Indonesia, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1997).

Foreign-Affiliates' Share of Petroleum Refining Capacity Continued Decline Begun in 1994

The decline in the foreign-affiliated share of petroleum refining capacity in 1996 can largely be attributed to capacity declines at BP America and Total Petroleum (Table 32). BP sold its Marcus Hook refinery in Pennsylvania to Tosco Corp., reportedly in response to the persistent weakness in U.S. refining margins,[82] and Total converted its Arkansas City refinery to a storage and blending facility to expand its marketing network and produce more value-added specialty products.[83] However, Shell Oil Co. increased its refining capacity by purchasing the Mobile, Alabama, refinery formerly owned by The Louisiana Land and Exploration Co. in August 1996.

The shares of retail gasoline outlets and volume of gasoline sold by foreign affiliates also registered declines of just under 1 percent in 1996 (Table 33). These declines were attributable primarily to Tosco's acquisition of Circle K from Bahraini-owned Investcorp. Apart from this transaction, the number of retail outlets of all foreign-affiliated companies increased, with Citgo supplying nearly 500 more retail outlets in 1996 than they had supplied in the prior year.

Figure 37. Foreign Affiliates' Share of U.S. Production of Oil, Gas, and Coal, and of U.S. Refining Capacity, 1980-1996



Sources: See Tables 7, 9, and 11 in this report. Energy Information Administration, *Performance Profiles of Major Energy Producers 1996, DOE/EIA-0206(96) (Washington, DC, January 1998),* and previous issues. U.S. Department of Energy, *Annual Report to Congress*, DOE/S-0010 (84) (Washington, DC, September 1984). Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy*, DOE/EIA-0466 (Washington, DC, 1984-1994).

Foreign-Affiliates' Share of Natural Gas Production Increased While Oil Remained Steady

In natural gas, the foreign-affiliated share of dry natural gas production regained part of its 1995 loss by growing almost 6 percent (Table 34), only the second increase since reaching its peak in 1989. The largest increases were for: Shell Oil Co. (by far the largest foreign-affiliated natural gas producer), in part due to higher production in the Gulf of Mexico;[84] Louis Dreyfus Natural Gas Co., largely through an ongoing expansion of developmental drilling;[85] and Forcenergy, in part through the acquisition of producing properties in and around Cook Inlet, Alaska.[86]

Foreign affiliates' share of oil (crude and natural gas liquids) production was virtually unchanged. However, the minimal increase in their share of oil production was the first since reaching a peak in 1988 (Table 34). Shell Oil Co.'s increase of 10 thousand barrels per day, largely from increased production in the Gulf of Mexico, particularly in the deepwater Gulf, and in California, was the largest among foreign-affiliated producers.[87] In 1996, Shell's Mars deepwater project began production in the Gulf of Mexico, as did their Popeye field. Mars established, at the time, a world water-depth record of 2,940 feet for a permanent drilling and production platform. In contrast, BP America, the largest foreign-affiliated oil producer, recorded a production decrease of almost 10 thousand barrels per day, with production from Alaska's Prudhoe Bay declining by 31 thousand barrels per day while BP's Gulf of Mexico production rose 13 thousand barrels per day and production from other areas rose 8 thousand barrels per day.[88]

Foreign-affiliated companies' shares of both oil reserves and natural gas reserves increased in 1996 (Table 35). Three companies, BP America, Anadarko Petroleum, and Forcenergy, were the largest contributors to the increase in oil reserves (Table 34). BP America had the largest increase in reserves, principally from the Northstar field in Alaska and the Troika field in the deep waters of the Gulf of Mexico.[89] While extensions, discoveries, and other additions were the largest contributor to increased reserves for Anadarko,[90] net purchases of minerals-in-place was

Table 32. U.S. Refinery Operations of Foreign-Affillated U.S. Companies, 1994-1996

Company	Number of Refineries[a]			Total Crude Distillation Capacity[a]		
	1994	1995	1996	1994	1995	1996
Shell Oil Co.	5	6	7	748	796	897
BPAmerica	4	4	3	705	694	551
Star Enterprise	3	3	3	600	605	605
Petroleos de Venezuela	4	4	4	545	545	542
Clark USA	2	3	3	124	309	309
Lyondell-Citgo Refining	1	1	1	265	265	258
Deer Park Refinery[d]	1	1	1	216	265	256
Fina	2	2	2	220	234	237
Total Petroleum, North America	4	4	3	198	198	142
Uno-Ven	1	1	1	145	145	145
BHP Petroleum Americas Refining	1	1	1	95	95	95
Transworld Oil USA	1	1	1	13	13	14
Total Foreign-Affiliated	36	31	30	4,479	4,154	4,051
Total United States	173	169	163	15,318	15,354	15,433
Percent Foreign-Affiliated	20.8	18.3	18.4	29.2	27.1	26.2

[a]Refineries operable as of January 1st of following year.
[b]Castle Energy sold one refinery in September 1995 and shut down their other refinery in October 1995.
[c]Pacific Refining shut down their Hercules, CA., refinery.
[d]Formerly Shell Oil/PMI Holdings
NF = No foreign affiliation during this period.
Sources: *Oil and Gas Journal* (December 23, 1996) and previous issues.

the largest source of increase for Forcenergy.[91] Saba Petroleum's reserves of oil, while still relatively small, more than doubled in 1996, largely through the acquisition of producing properties.[92]

Natural gas reserves of foreign-affiliated companies increased in 1996 (Table 35). The largest increase in natural gas reserves was reported by Midgard Energy, owned by Argentina-based YPF, S.A., whose U.S. reserves grew by 123 billion cubic feet. Midgard continued its aggressive drilling program on its mid-continent properties, completing 109 wells in 1996.[93] Both BHP Petroleum (Americas) and Shell Oil had large reserve decreases. In 1996, BHP Petroleum traded proven reserves for unproven ones by continuing to divest itself of many of its onshore and offshore U.S. properties, while acquiring a major exploration portfolio in the deep-water and ultra-deep-water Gulf of Mexico, where it became one of the largest leaseholders in depths greater than 1,500 feet.[94] Shell Oil, which produced the largest amount of natural gas among the foreign-affiliated companies, initiated natural gas production at its Mars project and from its Popeye field in 1996. It also sold 420 billion cubic feet of natural gas reserves (including four offshore blocks in the Gulf of Mexico) to Canadian Occidental Petroleum.[95]

Foreign Affiliates' Share of Mining Activity Increased

Foreign affiliates' share of U.S. coal production continued to rise in 1996, but the 1-percentage point increase was less than the pace of earlier years. Foreign affiliates' U.S. coal production increased 7 percent in 1996 (Figures 37 and 38 and Table 36), with Kennecott Energy -- owned at the time by London-based RTZ -- registering the largest increase (Table 36). Kennecott has been expanding its coal holdings in recent years, in line with the decision of its parent to concentrate on mining and related activities.[96] The Japanese-based ITOCHU Corporation gained a

Table 33. Branded Retail Outlets and Total Gasoline Supplied by Foreign-Affiliated U.S. Companies, 1995-1996

Company	1995	1996
Citgo Petroleum	14,054	14,529
Star Enterprise	9,378	9,378
Shell Oil Co.	8,767	8,900
BP America	6,800	6,752
Fina	2,631	2,571
Circle K	2,505	NF
Uno-Ven	2,395	2,247
Total Petroleum North America	1,991	2,106
Clark USA	842	863
Hawaiian Independent Refinery	28	30
Total for Foreign-Affiliated Companies[a]	49,391	47,375
U.S. Total[b]	190,246	187,892
Foreign-Affiliated Companies as Percent of U.S. Total	26.0	25.2
	Total Gasoline Supplied[c] (thousand barrels per day)	
Total for Foreign-Affiliated Companies[d]	2,204	2,145
U.S. Total[e]	7,588	7,647
Foreign-Affiliated Companies as Percent of U.S. Total	29.0	28.1

[a]Includes company-owned outlets and independent dealer outlets.
[b]The total includes all establishments selling gasoline at retail.
[c]Gasoline Supplied refers to average daily gasoline shipments.
[d]Disaggregated company numbers are considered proprietary by the Energy Information Administration.
[e]Total gasoline supplied.
NF = No foreign affiliation during this period.
Sources: Company station counts and total branded outlets: *National Petroleum News, Market Facts* 1996 and 1997. Company gasoline volumes: Energy Information Administration, Form EIA-782c. Total gasoline supplied: Energy Information Administration, *Monthly Energy Review November 1997*, DOE/EIA-0035(97/11) (Washington, DC, November 1997).

U.S. presence through their partnership with ARCO in purchasing Coastal Corporation's Utah coal reserves. This transaction alone added nearly 1 percentage point to foreign affiliates' overall share of U.S. coal production.

The U.S. uranium industry continued its nascent recovery in 1996: for the second consecutive year, mine production, uranium concentrate production, and expenditures on exploration and development all increased.[97] Still, U.S. exploration and development expenditures were only one half of their level in the mid-1980's (Table 37). Foreign affiliates' expenditures also rose in 1996, for the second year in row, but remained quite low compared to their level in the 1980's. Foreign affiliates increased their share of total U.S. exploration and development expenditures in 1996 to 44 percent.

Financial Performance of Foreign-Affiliated Energy Companies

The year 1996 was unusually favorable for the financial performance of petroleum and natural gas companies. As stated in the previous edition of this report, "The results for 1996...demonstrate...how the combination of unexpected demand increases and already tight supplies can have very substantial effects on energy producer profits."[98] Both upstream operations and downstream operations registered sizable gains in earnings in 1996 compared with recent years' results. For example, income from the FRS companies' U.S. oil and gas production operations more than tripled from 1995 to 1996 while income from their U.S. refining/marketing operations more than quadrupled.

Table 34. Net Production of Petroleum and Dry Natural Gas in the United States by Foreign-Affiliated U.S. Companies, 1994-1996

Company	Crude Oil and Natural Gas Liquids (thousand barrels per day)			Dry Natural Gas (billion cubic feet)		
	1994	1995	1996	1994	1995	1996
BP America	604.9	572.6	562.8	[a]25.2	[a]23.0	[a]29.0
Shell Oil Co	413.7	441.1	450.8	570.0	644.0	658.0
DuPont	90.4	NF	NF	318.0	NF	NF
Santa Fe Energy Resources	57.5	58.4	66.4	49.8	50.3	53.4
Anadarko Petroleum	31.0	30.1	27.9	173.0	172.0	165.0
Canadian Occidental Ltd	9.3	9.6	11.2	20.0	16.0	24.0
Forcenergy Gas Exploration	4.8	6.4	11.0	17.1	21.1	32.7
Fina	12.5	10.3	10.4	52.9	52.1	56.7
Norcen Energy Resources	4.7	4.9	5.9	32.5	40.5	48.7
Total Minatome Corp	7.7	6.7	5.5	28.2	32.0	34.0
Louis Dreyfus Natural Gas Co.	5.1	4.6	5.1	43.1	51.3	63.9
BHP Petroleum (Americas)	5.7	8.5	4.9	31.0	38.5	27.7
Elf Aquitaine Inc.	4.1	3.9	4.2	22.6	21.6	25.0
Chieftain Development International	1.9	1.6	2.0	12.6	10.1	23.0
Presidio Oil Co.	3.1	NF	NF	17.2	NF	NF
Saba Petroleum Co	1.8	1.9	2.2	1.0	0.9	1.1
YPF S.A.	0.0	1.1	1.2	0.0	47.5	53.1
Cairn Energy USA	0.3	1.2	0.7	3.9	10.4	10.2
Other Companies	2.8	1.4	1.2	21.1	10.1	13.1
Total Foreign-Affiliated	1,261.3	1,164.3	1,173.4	1,439.2	1,241.4	1,318.6
Total United States	8,642.5	8,626.0	8,607.0	18,747.0	18,599.0	18,793.0
Percent Foreign-Affillated	14.6	13.5	13.6	7.7	6.7	7.0

[a]Excludes natural gas consumed in Alaskan operations.

N F = No foreign affiliation during this period.

Note: Unless otherwise notes, company production is net ownership interest production. Totals may not equal sum of components due to independent rounding.

Sources: **Company data:** Form 10-K reports to the U.S. Securities and Exchange Commission and Annual Reports to Shareholders. **US totals**: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/09) (Washington, DC September 1997).

Accordingly, both foreign-affiliated energy companies and other U.S. energy companies posted improvements in their financial performance in 1996. Both groups of companies experienced similar revenue increases of 14 percent and 16 percent between 1995 and 1996, respectively (Table 38). However, the U.S. energy industry comparison group registered steeper gains in net income and cash flow.

The source of the comparatively lesser financial performance of the foreign affiliates was refining/marketing operations. Foreign affiliates with a primary industry of Standard Industrial Classification (SIC) Code 2911 (refined petroleum products including integrated refiners) had an aggregate net income increase of 16 percent, even though several foreign affiliates (Citgo Petroleum, Clark Refining and Marketing, and Lyondell Petrochemical) reported declines in net income. In contrast, non-foreign-affiliated U.S. energy companies classified in SIC 2911, a group that includes many of the vertically-integrated FRS companies, had a net income increase of 68 percent.

Financial performance of companies classified primarily as oil and gas producers (SIC 1311) in both groups improved greatly in 1996. Foreign-affiliated oil and gas producers had a net income increase of 235 percent between 1995 and 1996 and non-foreign-affiliated U.S. oil and gas producers had a 274-percent gain.

Table 35. Domestic Oil and Dry Natural Gas Proved Reserves and Production for Foreign-Affiliated U.S. Companies, 1994, 1995, and 1996

Fuel Type	Foreign-Affiliated Companies[a]	U.S. Total	Foreign-Affiliated Share of U.S. Total (percent)
Crude Oil and Natural Gas Liquids Proved Reserves	(million barrels)		
December 31, 1994	5,149	29,627	17.4
December 31, 1995	5,204	29,750	17.5
December 31, 1996	5,411	29,840	18.1
1995 Production	428	3,004	14.2
1996 Production	428	3,023	14.2
1995 Gross Reserve Additions[b]	482	3,127	15.4
1996 Gross Reserve Additions[b]	635	3,113	20.4
1995 Ratio of Gross Reserve Additions to Production	1.13	1.04	NM
1996 Ratio of Gross Reserve Additions to Production	1.48	1.03	NM
Dry Natural Gas Proved Reserves	(billion cubic feet)		
December 31, 1994	13,381	163,837	8.2
December 31, 1995	13,438	165,146	8.1
December 31, 1996	13,642	166,474	8.2
1995 Production	1,226	17,966	6.8
1996 Production	1,319	18,861	7.0
1995 Gross Reserve Additions[b]	1,498	19,575	7.7
1996 Gross Reserve Additions[b]	1,523	20,189	7.5
1995 Ratio of Gross Reserve Additions to Production	1.22	1.09	NM
1996 Ratio of Gross Reserve Additions to Production	1.15	1.07	NM

[a]Reserves and production are on a net ownership interest basis. The reserves and production data under each fuel type are for companies identified as foreign affiliated and reporting oil and/or natural gas production during 1996.

[b]Gross reserve additions = annual change in reserves + annual production.

NM = Not meaningful.

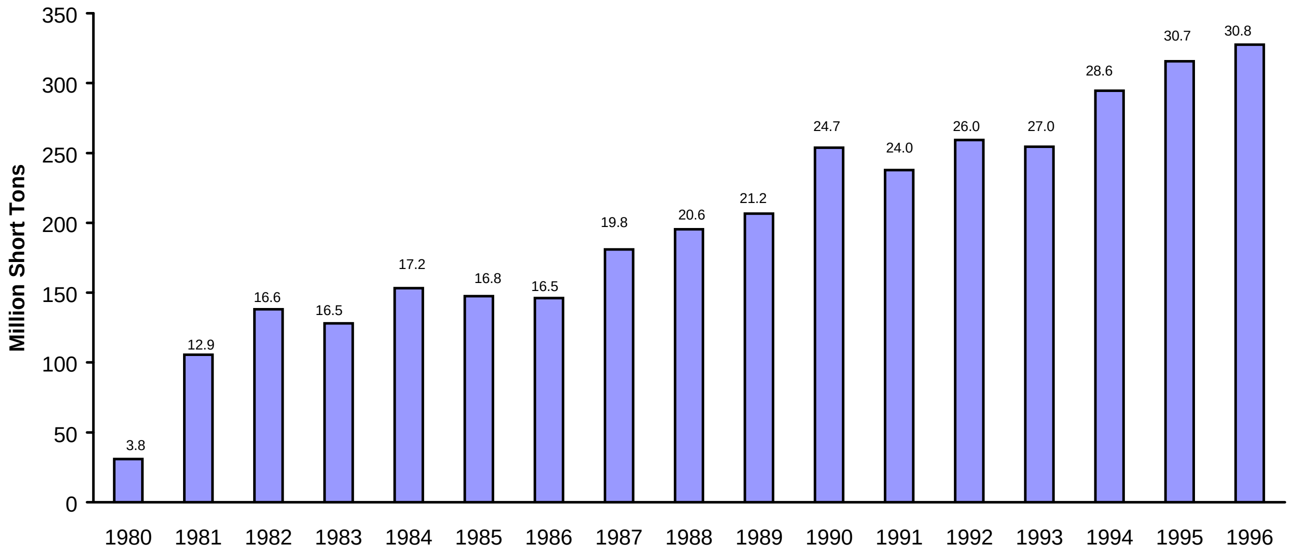
Sources: **Foreign-affiliated data:** Companies' Form 10-Ks filed with the U.S. Securities and Exchange Commission and annual reports to shareholders. **U.S. Totals:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996 Annual Report*, DOE/EIA-0216(96) (Washington, DC, November 1997).

U.S. Companies' Foreign Investment in Petroleum

The investment position of U.S. companies abroad (often referred to as direct investment abroad) in foreign petroleum has grown steadily in the 1990's (Table 39) while the FDI position in petroleum has generally declined (Table 30). The difference between the two series has widened (Figure 39) in the 1990's which was a reversal of the trend in the 1980's. This widening gap indicates that, in the global petroleum context, investment targets The abroad have been increasingly more attractive than U.S. prospects. This trend has been moderated in recent years, though, by the increased investment of foreign affiliates in oil and gas development in the Gulf of Mexico.

Some insight can be gained as to which regions outside the United States have been attracting investment in petroleum and natural gas in the 1990’s by examining capital and exploratory expenditures data for the FRS companies. The FRS companies account for at least 75 percent of U.S. companies’ capital expenditures for petroleum and natural gas outside the United States. Thus, the trends apparent in the FRS data should accurately represent the ongoing trends in petroleum-related direct investment abroad.

Figure 38. Production and Share of U.S. Total Bituminous Coal and Lignite for Foreign-Affiliated U.S. Companies, 1980-1996



Note: Percentage values appearing above bars indicate foreign-affiliates' share of U.S. production.
Sources: **1981**: Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1983*, DOE/EIA-0466 (Washington, DC, February 1985). **1982-1989**: *Keystone Coal Industry Manual*, 1990 and previous editions. **1990-1996**: Energy Information Administration, *Coal Industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997), Table 15, and previous issues.

Table 36. Bituminous Coal and Lignite Production and Source of Ownership of Foreign-Affillated Companies in the United States, 1995-1996
(Thousand Short Tons)

Controlling Company (Foreign-Ownership Interest)	1995	1996
Peabody Holding Co. (Hanson pic)	139,048	142,811
Consol Coal Group (DuPont) (Rheinbraun AG)	69,144	70,072
Kennecoft Energy Co. (RTZ pic)	53,211	62,527
Ashland Coal Co. (Carborex)	15,399	16,091
BHP Utah Minerals (Broken Hill Proprietary Co.)	14,631	13,228
Canyon Fuel Co. (Itochu Coal International)	NF	9,678
Costain Coal, Inc., (Costain Group)	10,421	9,342
Andalex Resources, Inc. (Andalex Resources, Inc.)	4,967	7,613
Westmoreland Resources, Inc. (Veba Kohle International)	7628	5111
Carter-Roag Coal Co. (Marquard and Bahls Coal Co.)	481	542
Great Western Resources, Inc. (British Investors)	728	0
Agip Coal, Inc. (Ente Nazionale Idrocarburi)	43	0
Total Foreign-Affiliated	**315,701**	**337,015**
Total United States	**1,028,263**	**1,063,856**
Percent Foreign-Affiliated	**30.7**	**31.7**

NF = No foreign affiliation during this period.
Note: Coal production refers to bituminous coal, subbituminous coal, and lignite coal production only.
Source: Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1995) and Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

Table 37. Foreign Participation in U.S. Uranium Exploration and Development, 1976-1995
(Million Dollars)

	Exploration and Development Expenditures by Foreign Companies	Total U.S. Exploration and Development Expenditures	Foreign Expenditures as a Percent of U.S. Total	Number of Foreign-Affiliated Companies
1976	13.2	170.7	8	15
1977	21.7	258.1	8	17
1978	39.3	314.3	13	31
1979	34.1	315.9	11	28
1980	37.6	267.0	14	28
1981	24.6	144.8	17	25
1982	14.6	73.6	20	14
1983	4.8	36.9	13	9
1984	6.6	26.5	25	9
1985	5.6	20.1	28	6
1986	12.0	22.1	54	8
1987	11.9	19.7	60	11
1988	8.9	20.1	44	11
1989	6.1	14.8	41	7
1990	2.5	17.1	15	9
1991	3.5	17.8	19	6
1992	8.0	14.5	55	6
1993	8.5	11.3	76	7
1994	1.9	3.7	51	8
1995	2.1	6.0	35	7
1996	4.4	10.1	44	8

Sources: Energy Information Administration, *Uranium Industry Annual 1995*, DOE/EIA-0478(97) (Washington, DC, April 1997), Table 2, and preceding issues. **Except Number of Companies, 1995 and 1996**: Energy Information Administration, Form EIA-868, "Uranium Industry Annual Survey" (1996 and 1995).

Asia-Pacific, Africa, and South America Lead Upswing in Exploration and Development in the 1990's

Regions registering more than a doubling in upstream expenditures by the FRS companies through the 1990's thus far are Asia-Pacific, Africa, and South America. The Asia-Pacific region accounted for the largest absolute increase in exploration and development spending ($2.3 billion) over the 1989-1996 period (Figure 40). The geographical scope of projects in this region includes mainly offshore activity in Australia, Indonesia, Malaysia, and Thailand with additional activity in Myanmar and China.

African locales overall had the steepest percentage increase among the regions. New areas off the West Coast of Africa, mainly Angola, as well as offshore prospects in Nigeria were the main targets in sub-Saharan Africa. Egypt has commanded the greatest share of FRS activity in North Africa but Algeria's recent reopening to western companies has resulted in heightened exploration and drilling by some FRS companies.

South America, like Africa, experienced a near-tripling in upstream expenditures by the FRS companies. Colombia and Trinidad/Tobago and, to a lesser degree, Argentina were the main targets in this region during most of the 1990's. In 1996, though, Venezuela became the primary focus of upstream activity in South America among the FRS companies. This development reflected the opening of Venezuela to oil and gas investment by foreign companies via joint ventures with the state-owned energy company, Petroleos de Venezuela (PDVSA).

Table 38. Selected Financial Information for Foreign-Affiliated U.S. Energy Companies, 1995-1996
(Billion Dollars)

	Foreign-Affiliated U.S. Energy Companies[a]			U.S. Energy Industry Comparison Group[b]		
	1995	1996	Percent Change	1995	1996	Percent Change
Financial Items						
Revenues	71.0	81.2	14.4	414.9	481.5	16.0
Net Income	3.0	3.9	28.1	15.4	28.3	83.9
Cash Flow[c]	8.1	8.8	8.6	47.4	58.1	22.5
Capital Expenditures	7.6	8.5	12.4	40.7	48.2	18.5
Cash Dividends	2.0	2.2	8.3	13.9	12.5	-10.4
Total Assets	65.0	71.8	10.6	407.4	449.7	-10.4
			(percent)			
Financial Ratios						
Return on Equity[d]	10.1	11.8		9.7	15.4	
Dividends/Net Income	67.0	56.7		90.6	44.1	
Dividends/Cash Flow	24.9	24.9		29.4	21.5	
Debt/Equity[e]	31.9	29.6		49.9	44.3	

[a] Includes incorporated U.S. energy companies that are foreign affiliated and for which publicly reported financial information is available. Also included are foreign parent companies for which data for U.S. operations were not separately disclosed. For 1995 these companies were: Anadarko Petroleum Corp., Arabian Shield Development Co., Arakis Energy Corp., Ashland Coal Inc., Blue Dolphin Energy Co., Cairn Energy USA Inc., Canadian Occidental Petroleum Ltd., Caspen Oil Inc., Chieftain International Inc., Circle K Corp., Citgo Petroleum, Clark Refining and Marketing Inc., Daleco Resources Corp., Fina Inc., Forcenergy Inc., Georesources Inc., Hondo Oil and Gas Co., Louis Dreyfus Natural Gas Corp., Lyondell Petrochemical Co., MSR Exploration, Magellan Petroleum Corp., NGC Corp., Norcen Energy Resources Ltd., Oceanic Exploration Co., Penn Virginia Corp., Ranger Oil Ltd., Rio Algom Ltd., Saba Petroleum Co., Santa Fe Energy Resources Inc., Santa Fe International Corp., Schlumberger Ltd., Shell Oil Co., Total Petroleum (North America) and Westmoreland Coal Co. The following companies were no longer foreign affiliated in 1996: Circle K Corp., Dalec Magellan Petroleum Corp., and Saba Petroleum Co.

[b] The comparison group is derived from aggregates available from Standard and Poor's PC Compustat Industrial File for the following four digit (SIC) industries: 1220 (bituminous coal, lignite mining), 1221 (bituminous coal, lignite surface mining), 1311 (crude petroelum and natural gas production), 1381 (oil and gas well drilling), 1382 (oil and gas field exploration), 1389 (oil and gas field services not elsewhere classified), and 2911 (petroleum refining). To obtain comparison group aggregates, the Compustat aggregates were adjusted by substracting out data for companies which have been identified as foreign affiliated, or whose operations are foreign-based, or foreign-based companies whose U.S. operations are already included in U.S. companies identified as foreign affiliated.

[c] Measured as cash flow from operations.

[d] Defined as net income divided by year-end stockholders' equity.

[e] Defined as year-end long-term debt divided by year-end stockholders' equity.

Note: Percent changes were calculated from unrounded data.

Source: Compiled from PC Compustat Industrial File and company annual reports.

Exploration and development expenditures directed toward Europe, though far short of doubling in the 1990's, nevertheless were up $2.0 billion, second only to the Asia-Pacific region. The main target in Europe has been, and continues to be, the North Sea. Much of the effort in this area has been directed to improving the yield of developed fields and extending the working life of production facilities and infrastructure. Exploration prospects have been extended beyond the North Sea to the north and west of the British Isles and towards the Arctic Circle off Norway.

Table 39. U.S. Direct Investment in Foreign Petroleum, 1980-1996
(Billion Dollars)

	Investment in Foreign Petroleum[a,b]	Total U.S. Direct Investment Abroad[a]	Petroleum as a Percent of Total
1980	47.6	215.4	22.1
1981	53.2	228.3	23.3
1982	57.8	207.8	27.8
1983	57.6	207.2	27.8
1984	58.1	211.5	27.5
1985	57.7	230.2	25.1
1986	58.5	259.8	22.5
1987	59.8	314.3	19.0
1988	57.8	335.9	17.2
1989	48.3	381.8	12.7
1990	52.8	430.5	12.3
1991	57.7	467.8	12.3
1992	58.5	502.0	11.7
1993	64.2	564.3	11.4
1994	67.1	640.3	10.5
1995	70.2	717.6	9.8
1996	75.5	796.5	9.5

[a]Direct Investment Abroad is the value of U.S. parents' net equity in, and outstanding loans to, affiliates outside the United States.
[b]The petroleum industry includes all phases of oil and gas exploration and production, petroleum refining, petroleum transport, and petroleum marketing.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1997) and preceding issues.

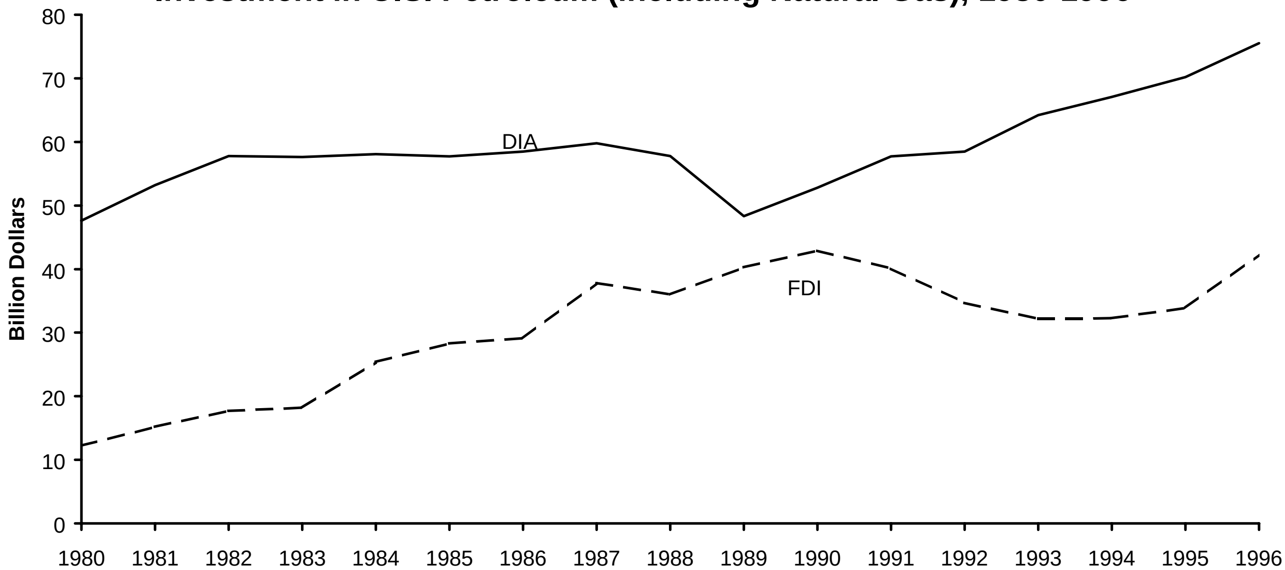
Canada evidenced the only drop in spending -- a very large, 75-percent drop. However, this decline is exaggerated due to the acquisition of Texaco Canada by Exxon in 1989. Excluding acquisitions of producing fields, exploration and development expenditures for Canada declined from $3.2 billion to $1.5 billion, or by a lesser 52 percent.

It's of note that, despite the publicity of the past few years, the Caspian Sea Region has seen relatively little actual exploration and development by the FRS companies. In 1997, exploration and development expenditures by the FRS companies in the entire Former Soviet Union were less than 2 percent of their worldwide expenditures.[99]

Downstream Focus Shifts to Asia-Pacific and South America in the 1990's

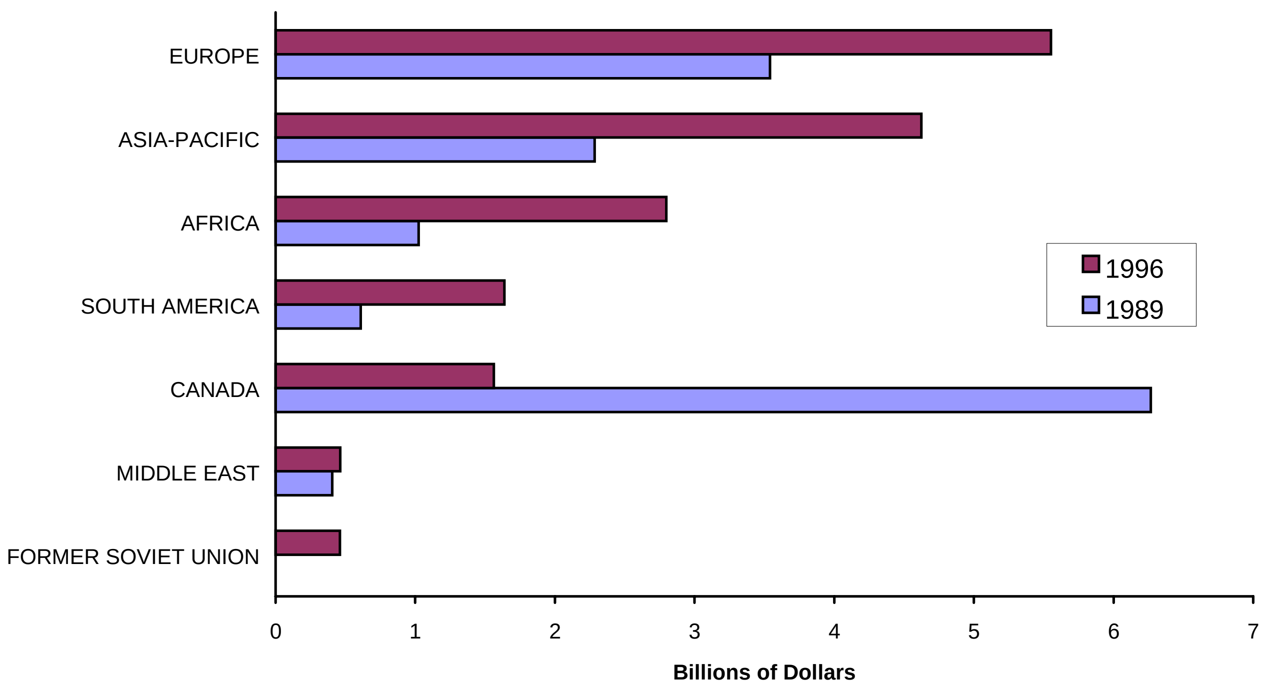
The FRS companies' refining capacity (measured by crude distillation capacity) outside the United States at the end of 1996 totaled 5.9 million barrels per day. Although the FRS companies' foreign refining capacity was nearly equal to their refining capacity in 1989 (Table 40), the composition across regions changed considerably during the 1990's. Responding to the greater growth in petroleum demand in the developing economies, both actual and projected, the FRS companies and their affiliates increased their refining capacity in the Asia-Pacific region by 21 percent and South America by 46 percent.

Figure 39. U.S. Direct Investment Abroad in Foreign Petroleum and Foreign Direct Investment in U.S. Petroleum (including Natural Gas), 1980-1996



Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, various issues.

Figure 40. Exploration and Development Expenditures for FRS Companies by Foreign Regions, 1989 and 1996



Source: Energy Information Administration, Form EI-28 (Financial Reporting System).

Table 40. Refinery Capacity Outside the United States for FRS Companies, 1989 and 1996
(Thousand Barrels per Day)

Region	1989		1996	
	Crude Distillation Capacity[a]	Percent Distribution	Crude Distillation Capacity[a]	Percent Distribution
Europe	2,867	48.4	2,649	44.6
Asia	1,800	30.4	2,176	36.6
Latin America	289	4.9	422	7.1
Canada	637	10.8	390	6.6
Other	331	5.6	304	5.1
Total	5,924	100.0	5,941	100.0

[a]Includes ownership shares in investees' refineries.

Source: Company filings of Securities and Exchange Commission Form 10-K, company annual reports, and supplements to annual reports.

The regions in which the FRS companies reduced their refining capacity in the 1990's were the slower growing regions of North America and Europe. Retrenchment of refining commitments by the FRS companies was most pronounced in the United States. Of the 1 million barrels per day of refining capacity the FRS companies took off their books, about 76 percent was due to sales of downstream assets to non-FRS companies, while the refineries contributed by FRS companies to joint ventures accounted for the balance. Outside the United States, Canada was the target of the greatest capacity reductions in the 1990's: 247 thousand barrels per day representing a 39-percent decline between 1989 and 1996. Exxon and their Canadian subsidiary, Imperial Oil, made the largest cutbacks in capacity, 191 thousand barrels per day, while Sun exited Canada in 1995, including the sale of a 70-thousand barrel per day refinery. Reductions in European refinery capacity totaled 218 thousand barrels per day, with Mobil accounting for 82 percent of the reductions largely through their divestiture of large refineries in Woerth, Germany, and Naples, Italy.

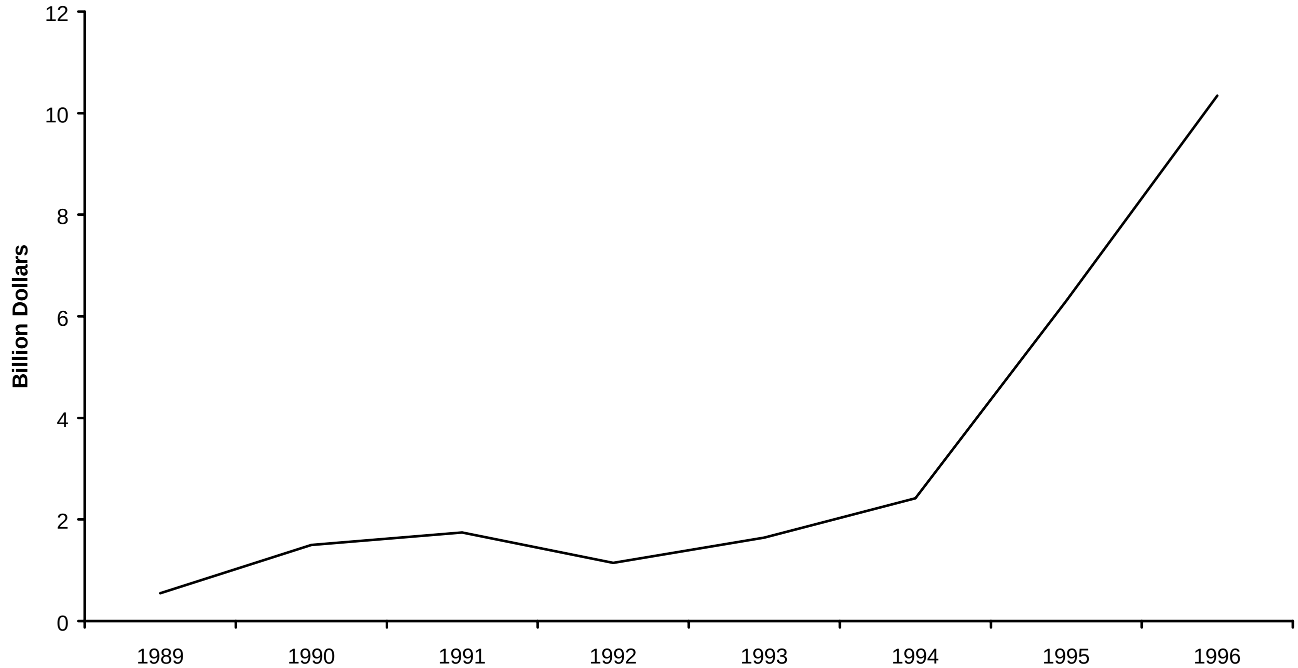
U.S. Companies' Foreign Investment in Electricity

Privatization and the deregulation of electric utilities abroad have presented U.S. companies with opportunities for investing in foreign electric power generation, transmission, and distribution. Provisions of the Energy Policy Act, enacted in 1992, removed Federal legislative impediments to investment in foreign ventures by U.S. utilities. In response to these policy changes, investment in electric power abroad by U.S. companies has surged in recent years.

The Department of Commerce publishes time-series data on direct investment abroad (DIA) in electric, gas, and sanitary services on a combined basis only. This series, at least in recent years, has been dominated by acquisitions of electricity assets. Prior to the passage of the Energy Policy Act, the DIA position in electric, gas, and sanitary services was less than $2 billion. After 1992, the DIA position increased sharply, particularly in 1995 and 1996, reaching $10 billion by the end of 1996 (Figure 41). However, the amount of equity capital outflows, while still large in 1996, was smaller than in 1995, while the DIA position in this account changed about the same amount in both years.[100]

The Commerce data likely understate the growth in investment in electricity abroad since some of the companies and their overseas subsidiaries who have made sizable outlays for overseas electricity assets are primarily in lines of business other than electricity. The Department of Commerce assigns data to categories based on the primary industry and location of the subsidiary. Some of the DIA that actually occurs in electricity shows up in the finance (except banking), insurance, and real estate (FIRE) account because, instead of going directly to purchase electric power companies, it funds them indirectly by establishing holding companies whose purpose is to acquire electric power companies. For example, nearly one half of the increase in total DIA in the United Kingdom in

Figure 41. U.S. Direct Investment Abroad in Electric, Gas, and Sanitary Services, 1989-1996



Sources: **1989-1991**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1994), p.161; **1992-1996**: *Survey of Current Business* (Washington, DC, September 1997), p. 147.

1996 was accounted for in the FIRE account. A large part of the equity capital outflows in this account funded the establishment of holding companies whose purpose was to acquire electric utility companies.[101]

Among targets of investment, Argentina, Australia, and the United Kingdom have received the most interest from U.S. investors in electric power, according to a 1996 EIA report.[102] Table 41 lists the U.S. companies who have made, or have attempted to make, large acquisitions (exceeding $100 million in value) in electricity in these countries, mainly during the 1995-1996 period. Most of the U.S. companies investing in electricity abroad are electric utilities with natural gas transmission companies also evidencing an interest. However, many U.S. electric utilities (over 80 percent of investor-owned utilities) have opted not to invest abroad. What motivations have led some utilities to invest overseas but left most utilities unmoved to do so?

A recent EIA report, released in late 1997, examined the characteristics of multinational U.S. utilities and wholly domestic utilities. The most outstanding difference was corporate growth.[103] According to the report, “Based on net fixed assets…foreign investing utilities grew at a 2.7-percent annual rate from 1987 through 1992…and at a 3.4-percent rate since then. Other electric utilities, overall, grew at annual rates of 1.5 percent and 1.0 percent over the same periods, respectively.” These findings are consistent with the view that privatization abroad has provided an investment channel for U.S. utilities that place a relatively high value on corporate growth.

Table 41. U.S. Companies with Acquisitions of Foreign Electricity Assets with a Value in Excess of $100 Million, 1995 and 1996

Country and Company	Functional Segment		
	Generation	Transmission	Distributon
Argentina			
AES	X		X
Citicorp Capital Investors			X
CMS Energy	X		
Community Energy Alternatives			X
Dominion Resources	X		
Duke Power	X	X	
El Paso Electric	X	X	X
PSI Energy	X		X
Australia			
CMS Energy	X		
Edison International	X		
Entenergy			X
General Public Utilities			X
Northern States Power	X		
PG&E		X	
PacificCorp			X
Texas Utilities			X
Utilicorp United			X
United Kingdom			
AES	X		
American Electric Power			X
Calenergy			X
Central and Southwest			X
Cinergy			X
Dominion Resources			X
Enron	X		
Entenergy			X
General Public Utilities			X
Mission Energy	X		
PacificCorp			X
Southern Company			X

Note: Generation includes independent power production assets.

Source: Energy Information Administration, *Electricity Reform Abroad and U.S. Investment,* DOE/EIA-0616 (Washington, DC, October 1997), Tables 8, 10, 17, 20.

Endnotes

[76]Shell Oil Company, *1996 Annual Report*, p. 37.
[77]Shell Oil Company, *1996 Annual Report*, pp. 38, 43.
[78] U.S. Department of Commerce, *Survey of Current Business* (Washington, DC, July 1997), pp. 38-39.
[79] U.S. Department of Commerce, *Survey of Current Business* (Washington, DC, September 1997), p. 82.
[80] Broken Hill Proprietary, *Securities and Exchange Commission Form 13-K* (January 12, 1996), p. 10.
[81] *Survey of Current Business* (Washington, DC, July 1997), pp. 40-41.
[82]The British Petroleum Company, p.l.c., *1996 Annual Report*, p. 17.
[83]Total Petroleum (North America), *Total 1996 Factbook*, Online, http://www.total.com/us/fb97/od_ref.htm (April 20, 1998).
[84]Shell Oil Co., *1996 Annual Report*, Online, http://www.shellus.com/1996/oiland2.htm (April 21, 1998).
[85]Louis Dryfus Natural Gas Co., *1996 Annual Review*, Online, http://www.ldng.com/growth96.htm (April 16, 1996).
[86]Forcenergy, Inc., *1996 Securities and Exchange Commission Form 10-K*, Online, http://www.sec.gov/Archives/edgar/data/946140/0000946140-97-000014.txt (April 21, 1996).
[87]Shell Oil Co., *1996 Annual Report*, Online, http://www.shellus.com/1996/oiland2.htm (April 21, 1998) and http://shellus.com/1996/letter3.htm (April 20, 1998).
[88]The British Petroleum Company, p.l.c., *1996 Annual Report*, p. 10.
[89]The British Petroleum Company, p.l.c., *1996 Securities and Exchange Commission Form 20-F*, p. 8.
[90]Anadarko Petroleum Corporation, *1996 Annual Report*, p. 59.
[91]Forcenergy, Inc., *1996 Securities and Exchange Commission Form 10-K*, Online, http://www.sec.gov/Archives/edgar/data/946140/0000946140-97-000014.txt (April 21, 1998).
[92]Saba Petroleum Co., *1996 Securities and Exchange Commission Form 10-KSB*, Online, http://www.sabapetroleum.com/item%206-1.htm (April 28, 1998).
[93]YPF S.A., *Securities and Exchange Commission Form 20-F*, Online, http://www.ypf.com.ar/invrel/areport96/financial/f20-1996b.html (April 20, 1998)
[94]The Broken Hill Proprietary Company Limited, *1996 Annual Report*, p. 31.
[95]Shell Oil Company, *1996 Annual Report*, Online, http://www.shellus.com/1996/oiland23.htm (April 21, 1998).
[96]Rio Tinto, p.l.c., “A world leader in mining,” Factsheet, 1997.
[97] Energy Information Administration, *Uranium Industry Annual 1996*, DOE/EIA-0478(96) (Washington, DC, April 1997).
[98]Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998), p. xi.
[99] For further discussion of the Caspian Sea Region, see the box entitled "Resource Development in the Caspian Sea Region," in Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998), pp. 38-39.
[100] U.S. Department of Commerce, *Survey of Current Business*, (Washington, DC, September 1997) Table 18. DIA is the sum of capital outflows and valuation adjustments, the latter of which reflect differences between changes in the DIA historical-cost position, measured at book value, and capital flows, measured at transaction value. Valuation adjustments were much larger negative values in 1995.
[101]Sylvia E. Bargas, U.S. Department of Commerce, *Survey of Current Business*, (Washington, DC, July 1997) pp. 37-38.
[102] Energy Information Administration, *Privatization and the Globalization of Energy Markets*, DOE/EIA-0609 (Washington, DC, October 1996), Chapter 5.
[103] Energy Information Administration, *Electricity Reform Abroad and U.S. Investment*, DOE/EIA-0616 (Washington, DC, October 1997), Chapter 1.

Appendix A

The Financial Reporting System (FRS)

Appendix A
The Financial Reporting System (FRS)

The legislation establishing the Financial Reporting System (FRS) requires the reporting of individual company financial and operating data to be on a "uniform and standardized basis" so that the data can be aggregated and comparisons can be made across companies and groups of companies.

The legislation also required the EIA to consult with the U.S. Securities and Exchange Commission in an effort to be consistent with other Federal financial accounting practices.

Accordingly, the FRS reporting form (Form EIA-28) necessarily incorporates a number of specific energy financial accounting principles and conventions. Details on these financial accounting concepts and principles can be found on the Energy Information Administration's Worldwide Web site at http://www.eia.doe.gov/emeu/perfpro/appenda.html. In particular, the interested reader is referenced to the following subheadings:

- *Survey Format* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#rptfrmt),
- *Petroleum Segment Overview* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#petovw),
- *Selection of Reporting Companies* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#criteria),
- *Financial Analysis Guide* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#faguide),
- *Accounting Practices* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#acctpr).

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1991-1997

Operating Statistics	1991	1992	1993	1994	1995	1996	1997
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	1,818.1	1,750.2	1,632.5	1,593.8	1,570.6	1,532.4	1,458.5
U.S. Industry[1]	3,266.0	3,219.0	3,127.0	3,059.0	3,004.0	3,023.0	3,002.0
FRS as a Percent of U.S. Industry	55.7	54.4	52.2	52.1	52.3	50.7	48.6
Natural Gas (billion cubic feet)							
FRS Companies	7,509.5	7,877.7	7,651.1	7,998.4	8,055.3	8,191.6	8,298.5
U.S. Industry[1]	17,202.0	17,423.0	17,789.0	18,322.0	17,966.0	18,861.0	19,211.0
FRS as a Percent of U.S. Industry	43.7	45.2	43.0	43.7	44.8	43.4	43.2
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	917.9	868.8	757.5	754.1	612.1	565.7	571.1
U.S. Industry[1]	2,243.7	2,383.0	2,640.9	2,788.7	2,810.0	2,946.6	3,191.0
FRS as a Percent of U.S. Industry	40.9	36.5	28.7	27.0	21.8	19.2	17.9
Refinery Capacity (thousand barrels per day)							
FRS Companies	11,203.0	10,952.0	10,714.0	10,642.0	10,427.0	10,477.0	9,507.0
U.S. Industry[1]	16,452.6	15,804.4	15,718.0	16,069.3	15,981.0	16,031.8	16,128.7
FRS as a Percent of U.S. Industry	68.1	69.3	68.2	66.2	65.2	65.4	58.9
Refinery Output[2] (thousand barrels per day)							
FRS Companies	11,122.0	10,994.0	10,822.0	10,812.0	10,652.0	10,954.0	10,030.0
U.S. Industry[1]	15,872.2	15,932.0	16,341.2	16,341.1	16,534.7	16,800.7	17,234.3
FRS as a Percent of U.S. Industry	70.1	69.0	66.2	66.2	64.4	65.2	58.2
Bituminous Coal and Lignite Production (million tons)							
FRS Companies	289.6	251.9	197.3	179.7	165.4	169.4	163.3
U.S. Industry[1]	996.0	994.1	941.1	1,028.9	1,028.3	1,059.1	1,085.3
FRS as a Percent of U.S. Industry	29.1	25.3	21.0	17.5	16.1	16.0	15.0

[1] U.S. area is defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.

[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1997 Annual Report December 1998). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,143.0 million barrels in 1997 and 3,150.2 million barrels in 1996. (See Energy Information Administration, Petroleum Supply Annual 1997, Volume I (June 1998), p. 1.) For dry natural gas production, the official Energy Information Administration U.S. totals are 18,930 billion cubic feet in 1997 and 18,793 billion cubic feet in 1996. (See Energy Information Administratic

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1997 Annual Report (December 1998). Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see Petroleum Supply Annual, 1996 and 1997. Coal production: Energy Information Administration, Form EIA-7A (Coal Production Report); see Coal Industry Annual 1997 (November 1998).

Table B2. Selected Financial Items for the FRS Companies and the S&P Industrials, 1996-1997
(Million Dollars)

Selected Financial Items	FRS Companies 1996	FRS Companies 1997	S&P Industrials 1996	S&P Industrials 1997
Income Statement				
Operating Revenues	541.4	525.1	3,554.2	3,787.0
Operating Expenses	492.7	-478.4	-3,161.2	-3,352.1
Operating Income	48.7	46.7	392.9	434.9
Interest Expense	-6.9	-6.4	73.3	77.1
Other Income[1]	3.4	4.1	-52.6	-78.7
Income Taxes	-20.0	-18.6	-121.9	-129.8
Net Income	32.0	32.1	218.4	226.4
Cash Flows from Operations[2]				
Net Income	32.0	32.1	218.4	226.4
Other Items, Net[3]	32.2	35.0	195.3	233.6
Net Cash Flow from Operations	64.2	67.1	413.7	460.0
Cash Flows from Investing Activities[2]				
Additions to PP&E	-44.2	-54.2	-271.9	-303.3
Other Investment Activities, Net[4]	6.8	6.4	-62.8	-56.2
Net Cash Flow from Investing Activities	-37.4	-47.8	-334.7	-359.5
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	10.7	17.9	266.0	263.5
Proceeds from Equity Security Offerings	1.2	1.5	33.1	29.3
Dividends to Shareholders	-15.6	-16.9	-79.3	-84.7
Reductions in Long-Term Debt	-18.9	-19.8	-224.7	-214.3
Stock Repurchases	-1.3	-7.9	-66.3	-94.9
Other Financing Activities, Net	-0.6	5.5	11.6	9.6
Net Cash Flow from Financing Activities	-24.5	-19.7	-59.6	-91.6
Effect of Exchange Rate Changes on Cash	0.0	-0.3	-1.5	-2.9
Increase (Decrease) in Cash and Cash Equivalents	2.3	-0.6	18.2	5.5

[1] "Other Income" includes other revenue and expense, discontinued operations, extraordinary items, and accounting changes.

[2] Items that add to cash are positive, and items that use cash are shown as negative values.

[3] "Other Items, Net" includes: DD&A, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of PP&E, changes in operating assets and liabilities, and other noncash items, excluding net change in short-term debt; other cash items, net.

[4] "Other Investment Activities, Net" includes additions to investments and advances and proceeds from disposals of PP&E.

Sources: Standard & Poors (S&P) Industrial data - Compustat PC Plus, a service of Standard & Poors. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B3. Balance Sheet Items and Financial Ratios for FRS Companies and S&P Industrials, 1996-1997

	FRS Companies		S&P Industrials	
	1996	1997	1996	1997
Balance Sheet	(billion dollars)			
Assets				
Current Assets	108.2	100.9	1,005.4	1,043.4
Noncurrent Assets				
Property, Plant, and Equipment				
Gross	635.0	636.9	2,481.2	2,638.7
Accumulated DD&A	-331.6	-333.3	-1,150.9	-1,240.0
Net	303.4	303.6	1,330.3	1,398.7
Investments and Advances	32.3	44.2	105.7	110.4
Other Noncurrent Assets	26.8	35.2	1,409.4	1,549.3
Subtotal Noncurrent Assets	362.4	382.9	1,815.2	1,951.0
Total Assets	470.6	483.8	3,850.9	4,101.9
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	110.1	106.9	876.1	944.4
Long-Term Debt	70.9	73.4	774.7	829.3
Other Long-Term Items	105.3	106.6	925.0	978.2
Minority Interest	6.6	8.2	41.1	41.7
Subtotal Liabilities and Other Items	292.9	295.1	2,616.9	2,793.6
Stockholders Equity				
Retained Earnings	156.3	160.8	923.2	964.4
Other Equity	21.4	27.9	310.8	343.9
Subtotal Stockholders Equity	177.8	188.7	1,234.0	1,308.3
Total Liabilities and Stockholders Equity	470.6	483.8	3,850.9	4,101.9
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	18.0	17.0	17.7	17.3
Net Income plus Interest/Total Invested Capital	15.7	14.7	14.5	14.2
Dividends/Net Cash Flow from Operations	24.3	25.2	19.2	18.4
Long-term Debt/Stockholders' Equity	38.9	38.9	62.8	63.4

Sources: Standard & Poor's (S&P) Industrial data - Compustat PC Plus, a services of Standard & Poor's. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B4. Consolidated Balance Sheet for FRS Companies , 1991-1997
(Billion Dollars)

Balance Sheet Items	1991	1992	1993	1994	1995	1996	1997
Assets							
Current Assets							
Cash & Marketable Securities	12.4	12.1	14.1	13.2	12.2	13.4	12.2
Trade Accounts & Notes Receivable	47.2	44.6	41.7	45.8	48.8	56.2	51.2
Inventories							
Raw Materials & Products	27.0	26.2	23.7	22.9	22.6	22.7	21.4
Materials & Supplies	5.2	4.6	4.3	4.4	4.1	3.8	3.7
Other Current Assets	9.2	10.4	9.6	10.2	10.9	12.1	12.4
Total Current Assets	101.0	97.9	93.5	96.6	98.6	108.2	100.9
Non-current Assets							
Property, Plant & Equipment							
Gross	581.4	599.9	607.9	624.1	640.2	635.0	636.9
Accumulated DD&A	275.9	290.2	300.0	315.4	329.8	331.6	333.3
Net	305.5	309.7	307.9	308.7	310.5	303.4	303.6
Investments & Advances to Unconsolidated Affiliates	20.1	21.9	23.6	25.9	29.0	32.3	44.2
Other Non-current Assets	20.6	24.2	26.3	26.2	26.5	26.8	35.2
Total Non-current Assets	346.2	355.7	357.8	360.8	366.0	362.4	382.9
Total Assets	447.1	453.6	451.3	457.4	464.6	470.6	483.8
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	56.5	53.1	49.1	51.5	53.1	61.4	57.7
Other Current Liabilities	47.6	48.7	47.0	45.8	50.8	48.8	49.2
Long Term Debt	90.9	93.5	89.4	88.1	84.6	70.9	73.4
Deferred Income Tax Credits	47.0	44.7	45.5	45.0	45.5	45.5	46.3
Other Deferred Credits	12.2	16.5	15.9	16.8	17.3	19.2	18.8
Other Long Term Items	21.1	34.9	37.7	39.3	40.7	40.6	41.6
Minority Interest in Consolidated Affiliates	4.2	4.8	5.0	5.1	5.8	6.6	8.2
Total Liabilities	279.6	296.3	289.6	291.7	297.9	292.9	295.1
Stockholders' Equity	148.9	139.2	142.0	145.0	151.4	156.3	160.8
Retained Earnings	18.6	18.1	19.8	20.7	15.3	21.4	27.9
Other Equity							
Total Stockholders' Equity	167.6	157.3	161.8	165.7	166.7	177.8	188.7
Total Liabilities & Stockholders' Equity	447.1	453.6	451.3	457.4	464.6	470.6	483.8
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	-3.2	-6.6	-7.3	0.7	1.5	1.2	-2.7
Foreign Currency Translation Adjustment for the Current Year	0.1	-3.3	-0.6	1.9	0.7	-0.4	-3.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B5. Consolidating Statement of Income for FRS Companies, 1997
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Nontraceables	Petroleum	Coal	Other Energy	Nonenergy
Operating Revenues	525,067	-13,750	441,647	3,789	6,694	86,687
Operating Expenses						
General Operating Expenses	439,290	-12,907	370,822	2,940	5,975	72,460
DD&A	29,569	500	24,545	449	189	3,886
General & Administrative	9,552	2,259	5,085	111	198	1,899
Total Operating Expenses	478,411	-10,148	400,452	3,500	6,362	78,245
Operating Income	46,656	-3,602	41,195	289	332	8,442
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	5,414	W	3,893	120	W	984
Other Dividend & Interest Income	1,922	1,922	-	-	-	-
Gain/Loss on Disposition of PP&E	2,716	W	2,107	12	W	589
Interest Expenses & Financial Charges	-6,419	-6,419	-	-	-	-
Minority Interest in Income	-896	-896	-	-	-	-
Foreign Currency Translation Effects	-258	-258	-	-	-	-
Other Revenue & (Expense)	2,280	2,280	-	-	-	-
Total Other Revenue & (Expense)	4,759	-3,110	6,000	132	164	1,573
Pretax Income	51,415	-6,712	47,195	421	496	10,015
Income Tax Expense	18,632	-2,755	17,532	83	150	3,622
Discontinued Operations	-481	W	W	0	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	-220	W	W	0	0	0
Net Income	32,082	-4,227	29,232	338	346	6,393

- = Not available.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B6. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1997
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipe-lines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	117,200	60,063	87,158	W	70,316	44,239	52,388	0
Refined Products Sales	129,004	W	129,111	0	130,446	W	136,709	0
Transportation Revenues	4,517	W	3,033	5,633	2,384	216	W	2,563
Management and Processing Fees	1,029	444	737	W	1,482	W	W	W
Other	7,698	1,215	6,660	171	4,395	681	4,501	W
Total Operating Revenues	259,448	61,991	226,699	6,114	209,023	46,079	195,041	2,583
Operating Expenses								
General Operating Expenses	219,405	35,455	216,489	2,813	178,079	21,628	188,545	2,300
DD&A	14,747	10,367	3,674	706	9,798	7,962	1,746	90
General & Administrative	3,130	934	1,788	412	2,117	707	1,653	43
Total Operating Expenses	237,282	46,756	221,951	3,931	189,994	30,297	191,944	2,433
Operating Income	22,166	15,235	4,748	2,183	19,029	15,782	3,097	150
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	1,404	659	260	485	2,489	1,509	971	W
Gain(Loss) on Disposition of PP&E	1,297	1,109	-56	244	810	737	61	W
Total Other Revenue & (Expense)	2,701	1,768	204	729	3,299	2,246	1,032	21
Pretax Income	24,867	17,003	4,952	2,912	22,328	18,028	4,129	171
Income Tax Expense	8,005	5,167	1,876	962	9,527	8,948	546	33
Discontinued Operations	W	W	W	W	W	W	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	W	W	W	0	0
Contribution To Net Income	16,424	11,925	3,156	1,343	12,808	9,087	3,583	138

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B7. Net Property, Plant, and Equipment (PP&E), Additions to PP&E, Investments and Advances, and Depreciation, Depletion, and Amortization (DD&A), by Lines of Business for FRS Companies, 1997
(Million Dollars)

	Year End Balance		Activity During Year		
	Net PP&E	Investments & Advances	Additions to PP&E	Additions to Investments & Advances	DD&A
Petroleum					
United States					
Production	85,641	6,531	19,898	294	10,367
Refining/Marketing					
Refining	25,638	1,442	1,860	-161	2,177
Marketing	14,981	800	2,118	95	1,145
Refining/Marketing Transport	1,813	614	443	100	135
Pipelines					
Marine	1,022	W	67	0	98
Other	777	W	109	0	119
Total U.S. Refining/Marketing	44,231	2,936	4,597	34	3,674
Rate Regulated Pipelines					
Refined Products	1,169	258	151	W	47
Natural Gas	10,389	1,715	714	386	349
Crude Oil and Liquids	5,533	697	334	W	310
Total Rate Regulated Pipelines	17,091	2,670	1,199	549	706
Total U.S. Petroleum	146,963	12,137	25,694	877	14,747
Foreign					
Production	67,864	8,580	15,023	1,891	7,962
Refining/Marketing	23,264	10,754	2,695	W	1,746
International Marine	1,094	71	14	W	90
Total Foreign Petroleum	92,222	19,405	17,732	2,678	9,798
Total Petroleum	239,185	31,542	43,426	3,555	24,545
Coal					
Foreign	W	W	W	W	W
United States	W	W	W	W	W
Total Coal	3,690	978	296	119	449
Other Energy					
Foreign	976	954	188	W	63
United States	2,738	297	2,034	W	126
Total Other Energy	3,714	1,251	2,222	533	189
Nonenergy					
Foreign Chemicals	10,625	3,917	1,965	932	1,039
U.S. Chemicals	29,963	2,707	4,382	1,809	2,165
Foreign Other Nonenergy	5,015	79	W	W	W
U.S. Other Nonenergy	4,307	973	W	W	W
Total Nonenergy	49,910	7,676	7,423	2,727	3,886
Nontraceable	7,091	2,716	878	751	500
Consolidated	303,590	44,163	54,245	7,685	29,569

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B8. Return on Investment for Lines of Business for FRS Companies Ranked by Total Energy Assets, 1996-1997
(Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	1996	1997	1996	1997	1996	1997	1996	1997
Petroleum	10.1	10.8	11.1	13.1	9.9	9.0	8.0	8.3
U.S. Petroleum	9.9	10.3	11.8	12.3	10.1	9.5	6.7	9.2
Oil and Gas Production	14.1	12.9	18.0	14.8	12.8	11.9	11.1	12.4
Refining/Marketing	4.4	6.7	2.6	7.5	8.1	8.6	1.2	0.7
Pipelines	6.9	6.8	16.6	19.8	5.9	1.6	5.7	10.5
Foreign Petroleum	10.6	11.5	10.6	13.7	9.4	7.7	13.2	5.3
Oil and Gas Production	12.8	11.9	14.1	15.2	9.9	8.5	13.6	5.2
Refining/Marketing	6.0	10.5	6.0	11.6	5.9	2.6	8.9	5.7
International Marine	2.2	11.8	4.0	12.0	W	W	W	0.0
Coal	9.9	7.2	-3.7	3.1	5.4	7.9	31.0	9.6
Other Energy	7.9	7.0	7.3	8.9	27.0	6.0	-13.6	6.3
Nonenergy	15.0	11.1	11.6	12.5	15.7	9.5	23.7	17.6

W = Data withheld to avoid disclosure.
Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B9. Research and Development Expenditures for FRS Companies, 1991-1997

(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
Sources of R&D Funds							
Federal Government	14	22	16	15	W	W	W
Internal Company	3,832	3,603	3,308	2,985	2,817	2,675	2,841
Other Sources	56	60	26	50	W	W	W
Total Sources	3,902	3,685	3,350	3,050	2,861	2,717	2,885
Breakdown of R&D Expenditures							
Oil & Gas Recovery	794	781	671	572	494	482	568
Other Petroleum	678	652	569	531	461	432	395
Coal Gasification/Liquefaction	39	W	W	W	W	W	W
Other Coal	17	W	W	W	W	W	2
Nuclear and Other Energy	95	80	121	116	50	51	54
Nonenergy	2,159	2,041	1,902	1,741	1,744	1,617	1,740
Unassigned	120	117	77	71	100	127	120
Total Expenditures	3,902	3,685	3,350	3,050	2,861	2,717	2,885

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B10. Size Distribution of Net Investment in Place for FRS Companies Ranked by Total Energy Assets, 1997
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	46.5	36.4	17.1	100.0
United States	32.1	45.5	22.4	100.0
Production	32.0	46.1	22.0	100.0
Refining/Marketing	40.8	40.6	18.5	100.0
Refining	40.9	38.6	20.4	100.0
Marketing	45.1	43.7	11.2	100.0
Rate Regulated Pipelines	12.2	54.3	33.5	100.0
Foreign	67.0	23.4	9.6	100.0
Production	57.2	29.7	13.1	100.0
Refining/Marketing	87.9	10.2	1.9	100.0
International Marine	99.3	0.6	0.1	100.0
Coal	27.4	35.5	37.1	100.0
Other Energy	31.5	55.4	13.1	100.0
Nonenergy	31.9	60.1	8.0	100.0
Chemicals	26.1	65.5	8.4	100.0
Other Nonenergy	58.2	35.5	6.3	100.0
Consolidated	43.9	40.5	15.5	100.0

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B11. Consolidated Statement of Cash Flows for FRS Companies, 1991-1997
(Million Dollars)

Cash Flows [1]	1991	1992	1993	1994	1995	1996	1997
Cash Flows From Operations							
Net Income	14,679	1,757	15,488	16,547	21,131	32,029	32,082
Minority Interest in Income	235	344	397	513	731	845	896
Noncash Items							
DD&A	30,017	31,033	30,355	30,667	36,698	29,331	29,569
Dry Hole Expense, This Year	2,841	1,986	1,673	1,805	1,510	1,812	2,069
Deferred Income Taxes	-2,062	-3,929	-990	509	-327	2,863	2,301
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-829	-350	-137	-372	-845	-226	-374
(Gain)/Loss on Disposition of PP&E	-1,808	-1,294	-941	-570	-2,445	-1,940	-2,716
Changes in Operating Assets and Liabilities and Other Noncash Items	2,923	3,284	2,646	-1,884	-763	-365	2,087
Other Cash Items, Net	1,823	11,927	1,705	1,084	2,808	-165	1,197
Net Cash Flow From Operations	47,819	44,758	50,196	48,299	58,498	64,184	67,111
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-1,075	-874	-306	-2,271	-4,137	-2,281	-5,579
Other	-43,812	-39,604	-37,755	-35,217	-40,356	-41,872	-48,666
Total Additions to PP&E	-44,887	-40,478	-38,061	-37,488	-44,493	-44,153	-54,245
Additions to Investments and Advances	-1,520	-1,483	-2,318	-1,588	-3,208	-5,799	-7,685
Proceeds From Disposals of PP&E	9,359	7,268	11,757	6,447	9,063	10,942	9,320
Other Investment Activities, Net	-103	-1,584	-2,242	-2,363	4,086	1,608	4,798
Cash Flow From Investing Activities	-37,151	-36,277	-30,864	-34,992	-34,552	-37,402	-47,812
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	22,120	24,745	18,982	12,500	19,929	10,708	17,901
Proceeds From Equity Security Offerings	491	3,438	2,146	2,614	3,471	1,171	1,507
Reductions in Long-Term Debt	-18,411	-25,284	-20,886	-13,760	-18,657	-18,883	-19,774
Purchase of Treasury Stock	-1,973	-824	-514	-1,010	-10,035	-1,299	-7,910
Dividends to Shareholders	-13,497	-13,521	-13,563	-14,906	-15,238	-15,585	-16,941
Other Financing Activities, Including Net Change in Short-Term Debt	-978	2,308	-4,102	-1,091	-2,350	-578	5,537
Cash Flow From Financing Activities	-12,248	-9,138	-17,937	-15,653	-22,880	-24,466	-19,680
Effect of Exchange Rate on Cash	-138	-359	-198	131	14	3	-255
Net Increase/(Decrease) in Cash and Cash Equivalents	-1,718	-1,016	1,197	-2,215	1,080	2,319	-636

[1] Items that add to cash are positive, and items that use cash are shown as negative values.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B12. Composition of Income Taxes for FRS Companies, 1991-1997
(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
Income Taxes (as per Financial Statements)							
Current Paid or Accrued							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	3,543	2,355	2,584	1,907	4,486	6,141	5,656
U.S. Federal Investment Tax Credit	-52	-41	-76	0	-162	-146	-93
Effect of Alternative Minimum Tax	412	450	-158	30	151	-325	-400
U.S. State & Local Income Taxes	695	759	462	528	649	745	794
Foreign Income Taxes							
Canada	119	558	660	705	634	745	932
Europe and Former Soviet Union [1]	2,710	2,066	1,947	2,300	2,752	3,862	2,927
Africa	1,563	1,509	1,256	1,127	1,204	1,956	1,926
Middle East	1,088	1,275	893	835	1,024	1,326	802
Other Eastern Hemisphere	2,248	2,180	2,075	2,085	1,882	2,195	1,901
Other Western Hemisphere	380	420	440	464	514	729	1,739
Total Foreign	8,108	8,008	7,271	7,516	8,010	10,813	10,227
Total Current	12,706	11,531	10,083	9,981	13,134	17,228	16,184
Deferred							
U.S. Federal, before Investment Tax Credit	-1,846	-1,723	-549	691	-793	1,410	1,477
U.S. Federal Investment Tax Credit	2	-43	-32	26	61	69	-2
Effect of Alternative Minimum Tax	-558	-564	117	-51	-158	312	400
U.S. State & Local Income Taxes	-69	20	-19	-56	-30	56	54
Foreign	385	-594	-456	43	537	930	519
Total Deferred	-2,086	-2,904	-939	653	-383	2,777	2,448
Total Income Tax Expense	10,620	8,627	9,144	10,634	12,751	20,005	18,632
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	25,120	22,542	24,777	29,592	34,233	52,808	51,415
Less: Foreign Source Income not Subject to U.S. Tax	3,671	2,753	3,233	3,575	4,038	6,230	6,438
Equals: Income Subject to U.S. Tax	21,449	19,789	21,544	26,017	30,195	46,578	44,977
Less: U.S. State & Local Income Taxes	757	748	509	438	440	782	779
Less: Applicable Foreign Income Taxes Deducted	907	1,121	638	327	377	554	312
Equals: Pretax Income Subject to U.S. Tax	19,785	17,920	20,397	25,252	29,378	45,242	43,886
Tax Provision Based on Previous Line	6,717	6,082	7,138	8,842	10,281	15,834	15,303
Increase/(Decrease) in Taxes Due To							
Foreign Tax Credits Recognized	-5,263	-4,596	-4,754	-4,831	-5,661	-6,926	-6,770
U.S. Federal Investment Tax Credit Recognized	-67	-83	-108	-34	-97	-123	-137
Statutory Depletion	-86	-66	-39	-52	-70	-54	-61
Effect of Alternative Minimum Tax	-3	-87	-1	-14	0	1	0
Other	87	-826	-352	-1,314	-868	-1,273	-1,214
Actual U.S. Federal Tax Provision (Refund)	1,385	424	1,884	2,597	3,585	7,459	7,121

[1] OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B13. U.S. Taxes Other Than Income Taxes for FRS Companies, 1991-1997
(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
Production Taxes							
Oil and Gas Production	2,082	1,967	1,906	1,719	1,693	2,098	1,965
Coal	300	211	187	126	157	139	172
Other [1]	7	7	5	5	11	1	1
Total Production Taxes	2,389	2,185	2,098	1,850	1,861	2,238	2,138
Superfund	346	305	320	291	293	14	W
Import Duties	98	99	127	122	104	260	W
Sales, Use, and Property	2,690	3,035	3,104	3,089	2,886	2,516	2,407
Payroll	2,199	2,222	2,134	1,986	1,844	1,531	1,406
Other Taxes	1,253	1,307	638	630	566	514	559
Total Taxes Paid (Other Than Income Taxes)	8,975	9,153	8,421	7,968	7,554	7,073	6,601
Excise Taxes Collected	23,253	23,782	25,317	30,092	30,813	32,426	30,984

[1] Nuclear, Other Energy, and Nonenergy.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B14. Oil and Gas Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1991-1997
(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
United States							
Exploration							
Acquisition of Unproved Acreage	568	257	355	477	595	997	2,653
Geological and Geophysical	648	475	409	405	486	625	750
Drilling and Equipping [1]	2,002	1,185	1,370	1,887	1,833	2,338	2,905
Other [2]	1,051	758	652	619	596	693	684
Total Exploration	4,269	2,675	2,786	3,388	3,510	4,653	6,992
Development							
Acquisition of Proved Acreage	1,137	541	599	1,576	980	922	2,928
Lease Equipment	2,215	1,450	1,640	1,386	1,425	1,613	1,823
Drilling and Equipping [1]	4,250	3,487	4,012	4,524	5,433	6,154	8,551
Other [2]	2,334	2,161	1,895	1,714	1,086	1,290	1,734
Total Development	9,936	7,639	8,146	9,200	8,924	9,979	15,036
Total U.S. Exploration and Development	14,205	10,314	10,932	12,588	12,434	14,632	22,028
Foreign							
Exploration							
Acquisition of Unproved Acreage	349	175	291	343	214	745	565
Geological and Geophysical	1,142	1,127	813	932	843	869	897
Drilling and Equipping [1]	2,639	1,618	1,564	1,595	2,114	2,277	2,684
Other [2]	1,124	1,123	1,011	960	989	919	1,043
Total Exploration	5,254	4,043	3,679	3,830	4,160	4,810	5,189
Development							
Acquisition of Proved Acreage	179	143	407	737	371	1,932	1,641
Lease Equipment	2,075	2,382	2,476	1,329	1,537	2,064	2,207
Drilling and Equipping [1]	3,821	3,842	4,118	4,085	4,535	5,278	6,426
Other [2]	2,375	2,499	1,866	1,928	2,568	2,534	2,468
Total Development	8,450	8,866	8,867	8,079	9,011	11,808	12,742
Total Foreign Exploration and Development	13,704	12,909	12,546	11,909	13,171	16,618	17,931

[1] Expenditure incurred in a given year not cumulative (includes work in progress adjustment).

[2] Includes support equipment.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B15. Components of U.S. and Foreign Exploration and Development Expenditures for FRS Companies, 1997

(Million Dollars)

	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	3,218	2,653	1,747	906	565
Drilling and Equipping					
Dry Holes (Cumulative)	-	1,005	333	672	-
Oil Wells (Cumulative)	-	502	167	335	-
Gas Wells (Cumulative)	-	782	287	495	-
Work-in-progress Adjustment	-	616	202	414	-
Total Drilling and Equipping	5,589	2,905	989	1,916	2,684
Geological and Geophysical	1,647	750	345	405	897
Other, Including Direct Overhead	1,727	684	313	371	1,043
Total Exploration Expenditures	12,181	6,992	3,394	3,598	5,189
Development Expenditures					
Proved Acreage					
(Including Mergers and Acquisitions)	4,569	2,928	2,724	204	1,641
Drilling and Equipping					
Dry Holes (Cumulative)	-	390	201	189	-
Oil Wells (Cumulative)	-	2,715	1,601	1,114	-
Gas Wells (Cumulative)	-	3,088	1,966	1,122	-
Work-in-progress Adjustment	-	2,358	837	1,521	-
Total Drilling and Equipping	14,977	8,551	4,605	3,946	6,426
Lease Equipment	4,030	1,823	872	951	2,207
Other Development					
Support Equipment	762	332	324	8	430
Other, Including Direct Overhead	3,440	1,402	1,282	120	2,038
Total Development Expenditures	27,778	15,036	9,807	5,229	12,742
Total Exploration and Development Expenditures	39,959	22,028	13,201	8,827	17,931

W = Data withheld to avoid disclosure.

- = Not available.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B16. Exploration and Development Expenditures by Region, 1991-1997
(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
Exploration Expenditures							
U.S. Onshore	2,160	1,593	1,371	1,491	1,644	1,644	3,394
U.S. Offshore	2,109	1,082	1,415	1,897	1,866	2,827	3,598
Total United States	4,269	2,675	2,786	3,388	3,510	4,653	6,992
Canada	661	336	403	573	493	355	310
OECD Europe	2,192	1,544	1,313	1,063	1,242	1,345	1,681
Former Soviet Union and E. Europe	0	0	163	204	181	194	271
Africa	680	738	599	678	707	779	807
Middle East	258	273	225	104	90	45	49
Other Eastern Hemisphere	1,028	869	736	888	1,016	1,462	1,312
Other Western Hemisphere	435	283	240	320	431	630	759
Total Foreign	5,254	4,043	3,679	3,830	4,160	4,810	5,189
Worldwide Exploration Expenditures	9,523	6,718	6,465	7,218	7,670	9,463	12,181
Development Expenditures							
U.S. Onshore	7,430	5,703	5,843	6,324	6,051	6,087	9,807
U.S. Offshore	2,506	1,936	2,303	2,876	2,873	3,892	5,229
Total United States	9,936	7,639	8,146	9,200	8,924	9,979	15,036
Canada	1,070	770	1,156	1,262	1,406	1,210	1,688
OECD Europe	4,643	5,252	4,169	3,376	3,962	4,222	5,371
Former Soviet Union and E. Europe	0	0	100	93	178	267	357
Africa	845	655	873	714	1,336	2,014	2,171
Middle East	233	285	460	341	271	418	594
Other Eastern Hemisphere	1,359	1,540	1,733	1,870	1,414	2,670	1,672
Other Western Hemisphere	300	364	376	423	444	1,007	889
Total Foreign	8,450	8,866	8,867	8,079	9,011	11,808	12,742
Worldwide Development Expenditures	18,386	16,505	17,013	17,279	17,935	21,787	27,778
Total Exploration and Development Expenditures							
U.S. Onshore	9,590	7,296	7,214	7,815	7,695	7,913	13,201
U.S. Offshore	4,615	3,018	3,718	4,773	4,739	6,719	8,827
Total United States	14,205	10,314	10,932	12,588	12,434	14,632	22,028
Canada	1,731	1,106	1,559	1,835	1,899	1,565	1,998
OECD Europe	6,835	6,796	5,482	4,439	5,204	5,567	7,052
Former Soviet Union and E. Europe	0	0	263	297	359	461	628
Africa	1,525	1,393	1,472	1,392	2,043	2,793	2,978
Middle East	491	558	685	445	361	463	643
Other Eastern Hemisphere	2,387	2,409	2,469	2,758	2,430	4,132	2,984
Other Western Hemisphere	735	647	616	743	875	1,637	1,648
Total Foreign	13,704	12,909	12,546	11,909	13,171	16,618	17,931
Worldwide Exploration and Development Expenditures	27,909	23,223	23,478	24,497	25,605	31,250	39,959

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1991-1997
(Million Dollars)

	1991	1992	1993	1994	1995	1996	1997
United States							
Taxes Other Than Income Taxes	2,082	1,967	1,906	1,719	1,693	2,098	1,965
Other Costs	14,891	12,586	11,777	11,107	10,429	10,221	10,048
Total Production Costs	16,973	14,553	13,683	12,826	12,122	12,319	12,013
U.S. Onshore	13,939	12,057	11,148	10,342	9,769	9,855	9,506
U.S. Offshore	3,034	2,496	2,535	2,484	2,353	2,464	2,507
Canada							
Royalty Expenses	W	W	19	W	W	W	W
Taxes Other Than Income Taxes	W	W	56	W	W	W	W
Other Costs	1,797	1,388	1,210	1,141	1,082	993	961
Total Production Costs	1,893	1,464	1,285	1,234	1,174	1,082	1,049
OECD Europe							
Royalty Expenses	495	465	305	206	235	251	217
Taxes Other Than Income Taxes	229	257	214	274	311	400	360
Other Costs	4,353	4,199	3,617	4,128	4,116	3,996	3,950
Total Production Costs	5,077	4,921	4,136	4,608	4,662	4,647	4,527
Former Soviet Union and E. Europe							
Royalty Expenses	--	--	0	0	0	0	0
Taxes Other Than Income Taxes	--	--	0	1	W	W	W
Other Costs	--	--	54	64	W	W	W
Total Production Costs	--	--	54	65	128	134	192
Africa							
Royalty Expenses	295	282	W	W	W	W	W
Taxes Other Than Income Taxes	14	21	W	W	W	W	W
Other Costs	680	776	821	740	607	812	861
Total Production Costs	989	1,079	1,122	1,011	916	1,259	1,310
Middle East							
Royalty Expenses	W	62	W	W	W	W	W
Taxes Other Than Income Taxes	W	292	W	W	W	W	W
Other Costs	217	324	313	340	258	296	280
Total Production Costs	316	678	424	435	403	483	491
Other Eastern Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	730	685	630	433	400	542	456
Other Costs	1,420	1,400	1,173	1,132	1,110	1,161	1,144
Total Production Costs	2,150	2,085	1,803	1,565	1,510	1,703	1,600
Other Western Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	230	137	122	83	129	180	156
Other Costs	481	450	374	346	428	389	470
Total Production Costs	711	587	496	429	557	569	626
Total Foreign							
Royalty Expenses	968	991	789	613	680	901	891
Taxes Other Than Income Taxes	1,220	1,286	969	843	942	1,196	1,050
Other Costs	8,948	8,537	7,562	7,891	7,728	7,780	7,854
Total Production Costs	11,136	10,814	9,320	9,347	9,350	9,877	9,795

W = Data withheld to avoid disclosure.

-- = Not applicable.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B18. Oil and Gas Acreage for FRS Companies, 1991-1997

(Thousand Acres)

	1991	1992	1993	1994	1995	1996	1997
Net Acreage							
U.S. Onshore							
Developed	31,043	29,590	28,856	28,744	27,429	26,733	25,474
Undeveloped	53,923	44,433	42,196	35,698	38,792	31,659	31,154
U.S. Offshore							
Developed	5,237	5,202	4,799	4,818	6,154	5,470	5,343
Undeveloped	22,993	20,837	16,175	13,925	14,334	16,880	22,983
Foreign							
Developed	24,289	26,010	22,050	20,505	18,063	22,574	21,984
Undeveloped	668,581	578,568	500,238	444,427	449,255	445,176	472,106
Gross Acreage							
U.S. Onshore							
Developed	61,178	53,389	50,640	51,846	50,016	46,887	45,249
Undeveloped	84,382	68,413	65,051	57,865	61,651	53,775	55,530
U.S. Offshore							
Developed	10,673	10,602	9,753	10,112	11,291	9,668	10,665
Undeveloped	35,126	26,692	20,233	19,128	18,595	21,786	30,845
Foreign							
Developed	71,064	85,614	61,274	57,885	49,946	59,926	58,198
Undeveloped	1,267,096	1,055,350	937,683	855,790	892,178	857,130	924,839

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1991-1997

	1991	1992	1993	1994	1995	1996	1997
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	297	294	231	175	232	274	163
Oil Wells	155	112	108	101	104	91	90
Gas Wells	283	127	127	167	201	207	170
Total Exploratory Wells	735	533	466	443	538	572	424
Net Development Wells							
Dry Holes	326	193	236	203	262	319	301
Oil Wells	2,738	1,664	1,966	1,980	1,908	2,095	3,016
Gas Wells	1,354	1,582	1,664	1,865	2,156	2,049	2,261
Total Development Wells	4,418	3,439	3,865	4,048	4,326	4,463	5,577
Offshore							
Net Exploratory Wells							
Dry Holes	92	50	69	78	72	84	98
Oil Wells	41	21	22	13	32	36	31
Gas Wells	55	25	42	47	53	87	73
Total Exploratory Wells	189	95	133	138	157	206	202
Net Development Wells							
Dry Holes	20	19	13	17	18	23	46
Oil Wells	128	111	125	150	151	158	181
Gas Wells	81	46	98	120	95	153	168
Total Development Wells	228	176	236	287	265	334	396
Total United States							
Net Exploratory Wells							
Dry Holes	390	344	300	253	304	358	261
Oil Wells	196	132	130	114	137	127	121
Gas Wells	338	151	169	214	255	293	243
Total Exploratory Wells	924	627	599	581	695	778	626
Net Development Wells							
Dry Holes	345	212	249	220	280	342	347
Oil Wells	2,866	1,775	2,091	2,130	2,059	2,253	3,197
Gas Wells	1,435	1,628	1,761	1,985	2,252	2,202	2,429
Total Development Wells	4,646	3,615	4,101	4,335	4,591	4,797	5,973
Number of Net Wells Completed During Year for Total U.S. Industry							
Net Exploratory Wells							
Dry Holes	3,400	2,586	2,604	2,479	2,302	2,211	2,149
Oil Wells	1,211	983	876	836	866	825	887
Gas Wells	1,235	883	888	994	992	1,051	1,074
Total Exploratory Wells	5,846	4,452	4,367	4,309	4,160	4,087	4,110
Net Development Wells							
Dry Holes	4,120	3,441	3,666	2,862	2,778	2,977	3,163
Oil Wells	10,432	7,675	7,459	5,905	6,788	7,368	8,859
Gas Wells	8,198	7,225	9,079	8,517	7,284	8,093	10,282
Total Development Wells	22,750	18,341	20,204	17,284	16,849	18,437	22,304
Number of Net In-Progress Wells At Year End for FRS Companies							
Onshore							
Exploratory Wells	125	97	106	90	135	133	132
Development Wells	650	795	709	524	541	675	933
Total In-Progress Wells	775	892	815	614	676	808	1,064
Offshore							
Exploratory Wells	49	39	35	46	46	45	89
Development Wells	36	57	68	91	57	93	131
Total In-Progress Wells	85	96	103	137	103	138	220
Total United States							
Exploratory Wells	174	136	141	136	181	178	221
Development Wells	686	852	777	615	598	768	1,063
Total In-Progress Wells	860	988	918	751	779	946	1,284

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Adminstration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, July 1998, p. 83. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B20. U.S. Net Drilling Footage and Net Producing Wells For FRS Companies and U.S. Industry, 1991-1997
(Thousand Feet)

	1991	1992	1993	1994	1995	1996	1997
FRS Companies							
Onshore							
Exploratory Well Footage							
Dry Hole Footage	2,611	2,623	2,341	1,699	1,799	2,052	1,700
Oil Well Footage	1,208	964	974	796	836	732	1,027
Gas Well Footage	1,711	1,035	1,072	1,464	1,456	1,860	1,521
Total Exploratory Footage	5,530	4,622	4,387	3,959	4,091	4,644	4,248
Development Well Footage							
Dry Hole Footage	1,130	1,270	1,429	1,177	1,550	2,224	1,926
Oil Well Footage	12,928	9,192	11,407	10,269	10,053	10,956	14,534
Gas Well Footage	7,388	10,589	11,558	12,955	14,468	14,304	16,751
Total Development Footage	21,446	21,051	24,394	24,401	26,071	27,484	33,211
Offshore							
Exploratory Well Footage							
Dry Hole Footage	1,087	755	710	911	891	1,091	1,362
Oil Well Footage	487	275	304	132	408	408	397
Gas Well Footage	647	321	488	568	702	1,824	981
Total Exploratory Footage	2,221	1,351	1,502	1,611	2,001	3,323	2,740
Development Well Footage							
Dry Hole Footage	202	172	158	124	155	244	459
Oil Well Footage	1,086	871	1,267	1,597	1,588	1,704	1,736
Gas Well Footage	711	466	975	1,025	1,011	1,538	1,584
Total Development Footage	1,999	1,509	2,400	2,746	2,754	3,486	3,779
Total United States							
Exploratory Well Footage							
Dry Hole Footage	3,698	3,378	3,051	2,610	2,690	3,143	3,062
Oil Well Footage	1,695	1,239	1,278	928	1,244	1,140	1,424
Gas Well Footage	2,358	1,356	1,560	2,032	2,158	3,684	2,502
Total Exploratory Footage	7,751	5,973	5,889	5,570	6,092	7,967	6,988
Development Well Footage							
Dry Hole Footage	1,332	1,442	1,587	1,301	1,705	2,468	2,385
Oil Well Footage	14,014	10,063	12,674	11,866	11,641	12,660	16,270
Gas Well Footage	8,099	11,055	12,533	13,980	15,479	15,842	18,335
Total Development Footage	23,445	22,560	26,794	27,147	28,825	30,970	36,990
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	19,360	14,204	14,752	14,570	13,562	13,648	13,822
Oil Well Footage	7,149	5,853	5,449	5,277	5,502	5,678	6,557
Gas Well Footage	7,402	4,936	5,020	5,934	6,398	6,369	7,418
Total Exploratory Footage	33,910	24,993	25,222	25,781	25,462	25,695	27,797
Development Well Footage							
Dry Hole Footage	19,141	16,567	17,610	14,807	14,353	15,800	17,373
Oil Well Footage	46,460	37,446	36,632	30,824	32,776	34,148	44,502
Gas Well Footage	42,219	40,696	54,846	54,066	45,098	50,766	65,463
Total Development Footage	107,819	94,709	109,088	99,696	92,227	100,715	127,337
Number of Net Producing Wells for FRS Companies							
Onshore							
Oil Wells	123,426	112,782	106,760	105,679	94,867	87,461	75,493
Gas Wells	43,591	46,308	46,535	49,237	50,388	48,779	48,779
Total Producing Wells	167,017	159,089	153,295	154,916	145,256	136,240	124,272
Offshore							
Oil Wells	5,337	5,021	4,274	4,179	4,180	3,552	3,760
Gas Wells	2,887	2,709	2,643	2,895	3,042	2,556	2,898
Total Producing Wells	8,224	7,730	6,917	7,074	7,221	6,108	6,658
Total United States							
Oil Wells	128,763	117,803	111,034	109,858	99,047	91,013	79,253
Gas Wells	46,478	49,016	49,178	52,132	53,430	51,335	51,677
Total Producing Wells	175,241	166,819	160,212	161,990	152,477	142,348	130,930

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1991-1997

	1991	1992	1993	1994	1995	1996	1997
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	101.3	65.1	71.7	111.2	107.5	86.2	22.8
Oil Wells	38.2	19.7	47.9	42.0	66.6	46.0	10.7
Gas Wells	54.0	29.6	46.8	105.1	74.0	96.1	49.2
Total Exploratory Wells	193.5	114.4	166.4	258.3	248.1	228.3	82.7
Development Wells							
Dry Holes	32.3	29.3	47.4	59.6	42.7	48.1	59.6
Oil Wells	169.6	211.1	334.6	174.2	569.5	559.4	778.6
Gas Wells	97.0	39.4	292.9	416.6	189.6	233.7	275.1
Total Development Wells	298.9	279.8	674.9	650.4	801.8	841.2	1,113.3
Net In-Progress Wells at Year	29.3	31.7	65.3	57.6	43.1	17.2	30.6
Net Producing Wells							
Oil Wells	13,996.6	12,597.5	11,704.3	11,268.5	9,793.9	8,719.5	9,364.7
Gas Wells	6,094.0	5,927.2	5,740.2	5,953.3	5,998.6	5,784.8	6,199.5
Total Producing Wells	20,090.6	18,524.7	17,444.5	17,221.8	15,792.5	14,504.3	15,564.2
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	77.6	47.4	33.4	33.7	42.1	49.4	56.6
Oil Wells	8.2	16.2	11.8	13.3	21.4	14.5	19.2
Gas Wells	15.0	11.8	14.6	11.2	10.6	11.4	8.9
Total Exploratory Wells	100.8	75.4	59.8	58.2	74.1	75.3	84.7
Development Wells							
Dry Holes	5.4	2.6	3.6	1.5	2.2	5.3	3.2
Oil Wells	52.0	38.2	59.9	60.4	72.4	77.6	80.7
Gas Wells	26.5	25.8	28.8	24.5	29.0	31.0	25.1
Total Development Wells	83.9	66.6	92.3	86.4	103.6	113.9	109.0
Net In-Progress Wells at Year	77.0	70.5	76.3	74.5	73.0	68.7	62.7
Net Producing Wells							
Oil Wells	1,462.0	1,459.3	1,479.3	1,430.2	1,359.4	1,445.5	1,328.0
Gas Wells	645.4	647.5	687.0	720.7	741.9	765.2	766.8
Total Producing Wells	2,107.4	2,106.8	2,166.3	2,150.9	2,101.3	2,210.7	2,094.8
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	54.5	65.3	37.9	32.0	28.4	19.8	25.3
Oil Wells	W	W	W	W	W	W	W
Gas Wells	W	W	W	W	W	W	W
Total Exploratory Wells	73.9	84.8	52.8	47.9	42.8	44.0	46.1
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	82.7	91.1	72.2	105.7	109.7	133.0	151.4
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	94.1	103.5	81.8	117.7	119.2	144.0	157.6
Net In-Progress Wells at Year End	44.0	34.4	21.3	45.1	41.9	36.9	29.0
Net Producing Wells							
Oil Wells	1,294.2	1,374.1	1,322.9	1,442.2	1,509.0	1,688.9	1,644.6
Gas Wells	20.6	26.8	25.8	34.4	41.9	49.9	59.5
Total Producing Wells	1,314.8	1,400.9	1,348.7	1,476.6	1,550.9	1,738.8	1,704.1

See footnotes at end of table.

Table B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1991-1997 (Continued)

	1991	1992	1993	1994	1995	1996	1997
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	60.5	47.6	43.9	47.4	47.4	42.6	39.8
Oil Wells	21.1	22.9	8.3	11.6	13.1	21.6	16.1
Gas Wells	11.4	10.0	16.4	14.5	44.4	46.3	15.8
Total Exploratory Wells	93.0	80.5	68.6	73.5	104.9	110.5	71.7
Development Wells							
Dry Holes	14.5	11.0	8.7	5.2	1.5	3.7	4.7
Oil Wells	106.4	106.7	124.9	115.7	92.7	103.1	162.6
Gas Wells	48.6	71.9	62.7	45.9	32.4	91.7	116.5
Total Development Wells	169.5	189.6	196.3	166.8	126.6	198.5	283.8
Net In-Progress Wells at Year End	89.4	71.5	83.8	71.9	92.5	72.4	61.4
Net Producing Wells							
Oil Wells	1,532.1	1,650.2	1,666.0	1,714.9	1,476.2	1,622.0	1,767.0
Gas Wells	321.1	373.2	393.9	437.9	401.4	561.2	633.8
Total Producing Wells	1,853.2	2,023.4	2,059.9	2,152.8	1,877.6	2,183.2	2,400.8
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	15.1	6.9	8.1	7.5	9.2	12.4	5.7
Oil Wells	W	W	W	W	W	W	W
Gas Wells	W	W	W	W	W	W	W
Total Exploratory Wells	25.6	12.0	19.8	15.5	13.9	23.4	10.4
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	87.4	87.0	78.8	85.6	120.5	123.3	141.4
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	93.4	89.0	87.2	94.3	133.1	129.8	148.3
Net In-Progress Wells at Year End	9.6	7.4	15.6	14.8	20.2	16.1	24.4
Net Producing Wells							
Oil Wells	3,145.5	2,938.3	3,032.6	2,939.6	2,980.6	2,478.9	605.0
Gas Wells	44.5	42.0	65.4	48.7	57.6	77.3	72.2
Total Producing Wells	3,190.0	2,980.3	3,098.0	2,988.3	3,038.2	2,556.2	677.2
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	309.0	232.3	195.0	231.8	234.6	210.4	150.2
Oil Wells	95.5	81.0	93.0	88.5	119.7	110.9	71.0
Gas Wells	82.3	53.8	79.4	133.1	129.5	160.2	74.4
Total Exploratory Wells	486.8	367.1	367.4	453.4	483.8	481.5	295.6
Development Wells							
Dry Holes	61.3	52.2	71.1	77.2	51.9	67.9	75.5
Oil Wells	498.1	534.1	670.4	541.6	964.8	996.4	1,314.7
Gas Wells	180.4	142.2	391.0	496.8	267.6	363.1	421.8
Total Development Wells	739.8	728.5	1,132.5	1,115.6	1,284.3	1,427.4	1,812.0
Net In-Progress Wells at Year End	249.3	215.5	262.3	263.9	270.7	211.3	208.1
Net Producing Wells							
Oil Wells	21,430.4	20,019.4	19,205.1	18,795.4	17,119.1	15,954.8	14,709.3
Gas Wells	7,125.6	7,016.7	6,912.3	7,195.0	7,241.4	7,238.4	7,731.8
Total Producing Wells	28,556.0	27,036.1	26,117.4	25,990.4	24,360.5	23,193.2	22,441.1

[1]OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

W = data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B22. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1996 and 1997

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	1996	1997	Percent Change	1996	1997	Percent Change	1996	1997	Percent Change
Exploration									
Oil Wells									
Drilling and Equipping Costs	295.0	502.0	70.2	102.0	167.0	63.7	193.0	335.0	73.6
Wells Completed	126.6	121.4	-4.1	91.1	90.3	-0.9	35.5	31.1	-12.4
Cost per Well (thousand	2,330.0	4,135.0	77.5	1,120.0	1,849.0	65.2	5,437.0	10,772.0	98.1
Average Depth (thousand	9.0	11.7	30.3	8.0	11.4	41.5	11.5	12.8	11.1
Cost per Foot (dollars)	258.8	352.5	36.2	139.3	162.6	16.7	473.0	843.8	78.4
Gas Wells									
Drilling and Equipping Costs	730.0	782.0	7.1	221.0	287.0	29.9	509.0	495.0	-2.8
Wells Completed	293.4	242.8	-17.2	206.5	170.3	-17.5	86.9	72.5	-16.6
Cost per Well (thousand	2,488.0	3,221.0	29.4	1,070.0	1,685.0	57.5	5,857.0	6,828.0	16.6
Average Depth (thousand	12.6	10.3	-17.9	9.0	8.9	-0.8	21.0	13.5	-35.5
Cost per Foot (dollars)	198.2	312.6	57.7	118.8	188.7	58.8	279.1	504.6	80.8
Dry Holes									
Drilling and Equipping Costs	877.0	1,005.0	14.6	340.0	333.0	-2.1	537.0	672.0	25.1
Wells Completed	357.8	261.4	-26.9	274.0	163.1	-40.5	83.8	98.3	17.3
Cost per Well (thousand	2,451.0	3,845.0	56.9	1,241.0	2,042.0	64.5	6,408.0	6,836.0	6.7
Average Depth (thousand	8.8	11.7	33.4	7.5	10.4	39.2	13.0	13.9	6.4
Cost per Foot (dollars)	279.0	328.2	17.6	165.7	195.9	18.2	492.2	493.4	0.2
Development									
Oil Wells									
Drilling and Equipping Costs	1,946.0	2,715.0	39.5	1,129.0	1,601.0	41.8	817.0	1,114.0	36.4
Wells Completed	2,252.8	3,197.0	41.9	2,094.8	3,015.8	44.0	158.0	181.2	14.7
Cost per Well (thousand	864.0	849.0	-1.7	539.0	531.0	-1.5	5,171.0	6,148.0	18.9
Average Depth (thousand	5.6	5.1	-9.4	5.2	4.8	-7.9	10.8	9.6	-11.2
Cost per Foot (dollars)	153.7	166.9	8.6	103.1	110.2	6.9	479.5	641.7	33.8
Gas Wells [1]	2,071.0	3,088.0	49.1	1,451.0	1,966.0	35.5	620.0	1,122.0	81.0
Wells Completed	2,201.5	2,429.0	10.3	2,049.0	2,260.6	10.3	152.5	168.4	10.4
Cost per Well (thousand dollars)	941.0	1,271.0	35.1	708.0	870.0	22.8	4,066.0	6,663.0	63.9
Average Depth (thousand feet)	7.2	7.5	4.9	7.0	7.4	6.1	10.1	9.4	-6.7
Cost per Foot (dollars)	130.7	168.4	28.8	101.4	117.4	15.7	403.1	708.3	75.7
Dry Holes									
Drilling and Equipping Costs [1]	261.0	390.0	49.4	171.0	201.0	17.5	90.0	189.0	110.0
Wells Completed	342.3	347.1	1.4	319.2	300.8	-5.8	23.1	46.3	100.4
Cost per Well (thousand dollars)	762.0	1,124.0	47.4	536.0	668.0	24.7	3,896.0	4,082.0	4.8
Average Depth (thousand feet)	7.2	6.9	-4.7	7.0	6.4	-8.1	10.6	9.9	-6.1
Cost per Foot (dollars)	105.8	163.5	54.6	76.9	104.4	35.7	368.9	411.8	11.6

[1] Million dollars.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 1997

	Beginning Reserves	Plus Reserve Additions [1]	Plus Net Purchases	Less Production	Equals Ending Reserves	Replacement Rate (percent)
Crude Oil and Natural Gas Liquids	(million barrels)					
U.S. Onshore						
Total U.S. Industry	25,595.0	2,581.0	0.0	2,415.0	25,762.0	106.9
FRS Companies	13,429.2	1,012.0	-796.6	1,095.8	12,548.8	92.4
All Other	12,165.8	1,569.0	796.6	1,319.2	13,213.2	118.9
U.S. Offshore						
Total U.S. Industry	4,245.0	1,099.0	0.0	587.0	4,757.0	187.2
FRS Companies	3,083.3	716.7	-58.0	362.7	3,379.3	197.6
All Other	1,161.7	382.3	58.0	224.3	1,377.7	170.4
U.S. Total						
Total U.S. Industry	29,840.0	3,680.0	0.0	3,002.0	30,519.0	122.6
FRS Companies	16,512.6	1,728.7	-854.7	1,458.5	15,928.1	118.5
All Other	13,327.4	1,951.4	854.7	1,543.5	14,590.9	126.4
FRS Companies' Foreign Oil Reserves						
Canada	1,933.6	145.3	-83.2	138.7	1,857.0	104.8
Europe	4,509.5	631.9	-2.2	554.9	4,584.3	113.9
FSU and Eastern Europe	365.1	71.9	0.0	9.6	427.4	750.1
Africa	3,199.3	W	W	309.8	3,417.7	168.9
Middle East	867.2	W	W	109.5	996.6	185.8
Other Eastern Hemisphere	1,672.0	265.0	-15.4	265.6	1,656.0	99.8
Other Western Hemisphere	881.2	175.2	-119.2	85.8	851.2	204.0
Total Foreign	13,427.9	2,015.8	-179.6	1,473.9	13,790.3	136.8
Worldwide Total for FRS Companies	29,940.5	3,744.5	-1,034.2	2,932.3	29,718.4	127.7
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	136,303.0	15,180.0	0.0	13,796.0	137,687.0	110.0
FRS Companies	57,231.2	4,963.4	-2,086.5	5,449.7	54,658.4	91.1
All Other	79,071.8	10,216.6	2,086.5	8,346.3	83,028.6	122.4
U.S. Offshore						
Total U.S. Industry	30,171.0	4,780.0	0.0	5,415.0	29,536.0	88.3
FRS Companies	20,513.8	2,593.2	-117.4	2,848.8	20,140.8	91.0
All Other	9,657.2	2,186.8	117.4	2,566.2	9,395.2	85.2
U.S. Total						
Total U.S. Industry	166,474.0	19,960.0	0.0	19,211.0	167,223.0	103.9
FRS Companies	77,745.0	7,556.6	-2,203.9	8,298.5	74,799.2	91.1
All Other	88,729.0	12,403.4	2,203.9	10,912.5	92,423.8	113.7
FRS Companies' Foreign Gas Reserves						
Canada	7,396.4	513.4	209.4	741.4	7,377.8	69.2
Europe	23,481.1	1,686.2	546.2	1,984.1	23,729.4	85.0
FSU and Eastern Europe	35.6	0.0	0.0	0.0	35.6	0.0
Africa	757.6	W	W	17.0	802.4	361.8
Middle East	426.5	160.5	0.0	91.4	495.5	175.6
Other Eastern Hemisphere	20,821.1	3,288.7	-350.7	1,710.6	22,048.4	192.3
Other Western Hemisphere	7,450.0	W	W	314.6	8,790.6	154.1
Total Foreign	60,368.2	7,486.3	284.3	4,859.0	63,279.8	154.1
Worldwide Total for FRS Companies	138,113.1	15,042.9	-1,919.6	13,157.5	138,078.9	114.3

[1] Excludes net purchases of minerals in place; includes crude oil and natural gas liquids (measured in millions of barrels) and natural gas (measured in millions of barrels of crude oil equivalent). The conversion factor for natural gas is 0.178 barrels of crude / 1000 cubic feet. Reserve additions include the net of corrections and adjustments.

W = Data withheld to avoid disclosure.

Note: "Net Ownership Interest" is defined as net working interest plus own royalty interest.

Sources: Industry data - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report, 1996 and 1997 (December 1997 and December 1998). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 1997

Reserves Statistics	Worldwide Total	United States Total	United States Onshore	United States Offshore	Total Foreign
Crude Oil and Natural Gas Liquids	(million barrels)				
Beginning of Period	29,940	16,513	13,429	3,083	13,428
Revisions of Previous Estimates	647	101	-4	104	546
Improved Recovery	702	419	403	16	283
Purchases of Minerals-in-Place	779	542	521	20	237
Extensions & Discoveries	2,395	1,209	613	596	1,187
Production	-2,932	-1,458	-1,096	-363	-1,474
Sales of Minerals-in-Place	-1,813	-1,396	-1,318	-78	-417
End of period	29,718	15,928	12,549	3,379	13,790
Proportionate Interest in Investee Reserves and Foreign Access Reserves	3,208	--	--	--	3,208
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	138,113	77,745	57,231	20,514	60,368
Revisions of Previous Estimates	1,478	-239	11	-250	1,717
Improved Recovery	696	290	283	7	406
Purchases of Minerals-in-Place	3,590	1,277	1,147	130	2,313
Extensions & Discoveries	12,870	7,506	4,669	2,837	5,363
Production	-13,158	-8,299	-5,450	-2,849	-4,859
Sales of Minerals-in-Place	-5,510	-3,481	-3,234	-247	-2,029
End of Period	138,079	74,799	54,658	20,141	63,280
Proportionate Interest in Investee Reserves and Foreign Access Reserves	21,847	--	--	--	21,847

See footnotes at end of table.

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies,1997 (Continued)

Reserves Statistics	Foreign					
	Total	Canada	Europe and Former Soviet Union [1]	Africa and Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Beginning of Period	13,428	1,934	4,875	4,067	1,672	881
Revisions of Previous Estimates	546	20	218	143	135	30
Improved Recovery	283	12	164	92	W	W
Purchases of Minerals-in-Place	237	20	60	W	W	W
Extensions & Discoveries	1,187	113	322	492	130	131
Production	-1,474	-139	-564	-419	-266	-86
Sales of Minerals-in-Place	-417	-104	-63	W	W	W
End of period	13,790	1,857	5,012	4,414	1,656	851
Proportionate Interest in Investee Reserves and Foreign Access Reserves	3,208	W	1,791	W	W	W
Natural Gas Reserves						
Beginning of Period	60,368	7,396	23,517	1,184	20,821	7,450
Revisions of Previous Estimates	1,717	9	423	-98	194	1,189
Improved Recovery	406	88	127	W	W	0
Purchases of Minerals-in-Place	2,313	631	618	0	W	W
Extensions & Discoveries	5,363	417	1,136	W	2,997	W
Production	-4,859	-741	-1,984	-108	-1,711	-315
Sales of Minerals-in-Place	-2,029	-421	-72	0	W	W
End of Period	63,280	7,378	23,765	1,298	22,048	8,791
Proportionate Interest in Investee Reserves and Foreign Access Reserves	21,847	W	18,718	W	W	W

[1] OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this

-- = Not applicable.

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B25. Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1997

	United States			Foreign Total
	Total	Onshore	Offshore	
Exploration and Development Expenditures (million dollars)				
FRS Companies	22,028.0	13,201.0	8,827.0	17,931.0
Percent Change	50.5	66.8	31.4	7.9
Wells Completed				
FRS Companies	6,598.7	6,000.9	597.8	2,107.6
Percent Change	18.4	19.2	10.7	10.4
Industry[1]	26,413.0	-	-	21,862.0
Percent Change	17.3	-	-	7.8
Success Rate[2]				
FRS Companies	90.8	92.3	75.8	89.3
Industry[1]	79.9	80.4	56.4	82.5
Crude Oil and NGL Production[3] (million barrels)				
FRS Companies	1,458.5	1,095.8	362.7	1,443.8
Percent Change	-4.8	-8.5	8.5	3.3
Industry [1]	3,002.0	2,415.0	587.0	22,174.0
Percent Change	-0.7	-3.3	11.8	-0.1
Crude Oil and NGL Reserve Interests (million barrels) [4]				
FRS Companies	15,928.1	12,548.8	3,379.3	16,998.3
Percent Change	-3.2	-6.2	9.5	3.8
Natural Gas Production (billion cubic feet)				
FRS Companies	8,298.5	5,449.7	2,848.8	4,904.3
Percent Change	1.3	1.3	1.3	3.7
Industry[1]	19,211.0	13,796.0	5,415.0	58,439.0
Percent Change	1.9	1.7	2.2	-4.3
Natural Gas Reserve Interests (billion cubic feet)				
FRS Companies	74,799.2	54,658.4	20,140.8	85,127.0
Percent Change	-1.6	-2.0	-0.7	4.8

See footnotes at end of table.

Table B25. Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1997 (Continued)

	Foreign						
	Total	Canada	Europe & Former Soviet Union [5]	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Exploration and Development Expenditures (million dollars)							
FRS Companies	17,931.0	1,998.0	7,680.0	2,978.0	643.0	2,984.0	1,648.0
Percent Change	7.9	27.7	27.4	6.6	38.9	-27.8	0.7
Wells Completed							
FRS Companies	2,107.6	1,196.0	193.7	137.6	66.1	355.5	158.7
Percent Change	10.4	11.8	2.4	7.4	10.4	15.0	3.6
Foreign Industry[1]	21,862.0	14,419.0	1,240.0	748.0	740.0	1,676.0	3,039.0
Percent Change	7.8	9.4	-0.9	6.3	9.0	14.3	1.1
Success Rate[2]							
FRS Companies	89.3	93.1	69.1	81.7	92.3	87.5	94.5
Foreign Industry[1]	82.5	80.4	76.0	84.0	91.6	81.7	92.9
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,503.9	138.7	579.2	309.8	124.8	265.6	85.8
Percent Change	1.7	4.6	-2.8	14.2	4.7	0.6	-11.0
Foreign Industry[1]	22,174.0	934.0	5,232.0	2,840.0	7,930.0	1,626.0	3,612.0
Percent Change	-0.1	4.9	2.1	2.3	6.8	1.3	-17.3
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	16,998.3	1,899.8	6,803.1	3,417.7	1,915.7	2,108.4	853.7
Percent Change	3.8	-2.3	5.8	6.8	7.2	-2.8	0.3
Natural Gas Production (billion cubic feet)							
FRS Companies	4,904.3	741.4	2,029.4	17.0	91.4	1,710.6	314.6
Percent Change	3.7	-8.7	1.5	-6.2	1.2	10.7	18.7
Foreign Industry[1]	58,439.0	5,535.0	31,731.0	3,322.0	5,885.0	7,702.0	4,264.0
Percent Change	-4.3	-5.4	-9.7	3.4	8.4	2.0	10.1
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	85,127.0	7,545.3	42,482.6	802.4	3,296.4	22,209.7	8,790.6
Percent Change	4.8	0.9	0.7	5.9	37.7	5.9	18.0

[1]Foreign industry levels defined as total activity outside of the United States except the People's Republic of China.

[2]Success Rate defined as the total number of successful well completions during the period divided by the total number of wells drilled.

[3]Crude oil plus natural gas liquids. Includes ownership interest production and foreign access production.

[4]Includes net ownership interest reserves (81.1 percent) and "Other Access" reserves (18.9 percent). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

[5]OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

- = Not available.

Sources: Reserve additions, U.S. - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1995, 1996, and 1997 Annual Reports. Wells completed, U.S. - special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information's Monthly Energy Review, July 1998, p. 83. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 1998 and 1997.* Wells Completed, Foreign - *World Oil*, August 1998 and 1997. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B26. U.S. and Foreign Refining/Marketing Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies, 1991-1997
(million barrels)

	1991	1992	1993	1994	1995	1996	1997
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	1,753	1,745	1,743	2,014	1,658	1,599	1,445
Purchases from Other U.S. Segments and Unconsolidated Affiliates	400	679	607	385	432	459	488
Purchases from Third Parties	3,914	3,883	3,925	3,937	4,100	4,488	4,423
Net Transfers from Foreign Refining/Marketing Segment	918	869	757	754	612	566	571
Total Sources	6,985	7,176	7,032	7,090	6,802	7,112	6,928
Dispositions							
Net Change in Inventories	-32	-8	31	48	23	21	14
Input to Refineries	3,658	3,611	3,565	3,636	3,565	3,563	3,259
Sales to:							
Unaffiliated Third Parties	3,040	3,171	3,261	3,235	2,961	3,291	3,327
Other Segments Excluding Foreign Refining/Marketing	320	401	175	172	252	237	328
Total Dispositions	6,985	7,176	7,032	7,090	6,802	7,112	6,928
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,241	1,150	1,163	1,335	1,249	1,371	1,391
Purchases							
Other Foreign Segments	61	77	85	95	93	88	W
Unconsolidated Affiliates	311	79	2	63	89	89	W
Unaffiliated Third Parties							
Foreign Access	131	111	114	120	107	145	228
Foreign Governments (Open Market)	580	774	725	726	621	844	851
Other Unaffiliated Third Parties	1,972	1,885	2,653	2,147	2,063	1,819	1,785
Net Transfers to U.S. Refining/Marketing Segment	-918	-869	-757	-754	-612	-566	-571
Total Sources	3,379	3,207	3,986	3,731	3,610	3,790	3,778
Dispositions							
Net Change in Inventories	-4	-8	-1	0	1	38	18
Input to Refineries	1,508	1,367	1,530	1,535	1,520	1,605	1,515
Sales	1,874	1,849	2,456	2,195	2,090	2,147	2,246
Total Dispositions	3,379	3,207	3,986	3,731	3,610	3,790	3,778

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B27. U.S. Purchases and Sales of Oil, Natural Gas, Other Raw Materials, and Refined Products, 1991-1997

	1991	1992	1993	1994	1995	1996	1997
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	129,380	124,868	111,654	104,471	111,556	138,397	124,648
Natural Gas	4,367	7,504	10,678	12,360	9,747	15,651	17,514
Other Raw Materials	2,195	2,496	3,196	3,498	3,892	2,697	3,159
Total Raw Materials	135,942	134,868	125,528	120,329	125,195	156,745	145,321
Refined Products							
Motor Gasoline	12,106	12,403	11,831	12,430	14,131	18,078	18,613
Distillate Fuels	5,738	6,008	6,629	6,626	6,773	9,634	9,565
Other Refined Products	9,136	9,261	8,467	8,389	10,114	10,246	9,141
Total Refined Products	26,980	27,672	26,927	27,445	31,018	37,958	37,319
U.S. Production Segment							
Crude Oil and NGL	4,186	2,816	2,458	2,660	3,353	5,163	3,657
Natural Gas	3,223	4,192	5,042	5,950	6,981	10,715	11,220
Total Raw Materials	7,409	7,008	7,500	8,610	10,334	15,878	14,877
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	64,948	63,564	56,612	49,752	53,544	69,485	68,550
Natural Gas	3,873	7,406	10,527	12,432	9,295	15,790	17,109
Other Raw Materials	929	1,175	1,720	2,201	2,325	1,276	1,499
Total Raw Materials	69,750	72,145	68,859	64,385	65,164	86,551	87,158
Refined Products							
Motor Gasoline	68,983	67,695	63,476	61,032	65,701	75,330	71,185
Distillate Fuels	35,535	33,920	33,064	30,568	30,420	41,618	36,962
Other Refined Products	23,467	22,525	21,107	23,190	24,577	24,577	20,964
Total Refined Products	127,985	124,140	117,647	114,790	120,698	141,525	129,111
U.S. Production Segment							
Crude Oil and NGL	32,372	29,585	25,734	23,468	26,303	32,948	30,604
Natural Gas	14,071	16,905	20,238	19,757	18,696	26,840	29,459
Total Raw Materials	46,443	46,490	45,972	43,225	44,999	59,788	60,063
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	6,985	7,176	7,032	7,090	6,802	7,112	6,928
Natural Gas (billion cubic feet)	2,884	4,593	6,022	7,479	6,543	7,506	7,120
Refined Products (million barrels)							
Motor Gasoline	427	467	487	563	588	677	689
Distillate Fuels	226	253	288	322	321	380	397
Other Refined Products	407	410	378	345	422	363	329
Total Refined Products	1,059	1,129	1,153	1,230	1,330	1,420	1,415
U.S. Production Segment							
Crude Oil and NGL (million barrels)	222	206	178	201	237	300	220
Natural Gas (billion cubic feet)	2,067	2,408	2,569	3,276	4,395	4,723	4,551
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,359	3,572	3,436	3,406	3,213	3,528	3,655
Natural Gas (billion cubic feet)	2,457	4,198	5,416	6,960	6,089	7,195	6,790
Refined Products (million barrels)							
Motor Gasoline	2,267	2,286	2,327	2,347	2,422	2,488	2,371
Distillate Fuels	1,347	1,364	1,400	1,392	1,374	1,562	1,473
Other Refined Products	1,137	1,128	1,082	1,172	1,183	1,069	1,008
Total Refined Products	4,751	4,778	4,810	4,911	4,979	5,119	4,852
U.S. Production Segment							
Crude Oil and NGL (million barrels)	2,078	2,044	1,898	1,889	1,875	1,933	1,863
Natural Gas (billion cubic feet)	8,761	9,712	9,801	10,810	12,108	12,281	12,420

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1991-1997

	1991	1992	1993	1994	1995	1996	1997
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,847	9,736	9,676	9,809	9,669	9,777	9,060
By Refineries of Others	5	5	5	5	5	5	5
Total Runs to Stills	9,852	9,741	9,681	9,814	9,674	9,782	9,065
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	-	-	-	-	-	1,302	768
Oxygenated Motor Gasoline	-	-	-	-	-	165	749
Other Motor Gasoline	-	-	-	-	-	3,410	2,980
Total Motor Gasoline	5,055	4,968	4,953	4,936	4,849	4,877	4,497
Distillate Fuels	2,954	2,931	2,916	3,030	2,901	3,323	2,921
Other Refined Products	3,113	3,095	2,953	2,846	2,902	2,754	2,612
Total Refinery Output	11,122	10,994	10,822	10,812	10,652	10,954	10,030
Refinery Capacity at End of Year	11,203	10,952	10,714	10,642	10,427	10,477	9,507
	(number of refineries)						
Number of Wholly-Owned Refineries	88	82	75	74	69	69	60
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,667	3,706	3,823	3,829	3,962	3,936	3,961
By Refineries of Others	632	749	312	304	323	506	340
Total Runs to Stills	4,299	4,455	4,135	4,133	4,285	4,442	4,301
Refinery Output at Own Refineries							
Motor Gasoline	1,097	1,098	1,114	1,122	1,175	1,172	1,041
Distillate Fuels	1,534	1,553	1,634	1,674	1,662	1,690	1,648
Other Refined Products	1,009	1,064	1,148	1,102	1,183	1,280	1,283
Total Refinery Output at Own	3,640	3,715	3,896	3,898	4,020	4,142	3,972
Refinery Output at Refineries of Others							
Motor Gasoline	188	199	85	85	70	107	75
Distillate Fuels	303	359	136	140	140	234	154
Other Refined Products	199	192	88	82	113	165	110
Total Refinery Output at Refineries of Others	690	750	309	307	323	506	339
Total Refinery Output	4,330	4,465	4,205	4,205	4,343	4,648	4,311
Refinery Capacity at End of Year	4,622	4,648	4,692	4,766	4,450	4,346	4,249
	(number of refineries)						
Number of Wholly-Owned Refineries	27	27	26	26	24	20	17
Number of Partially-Owned Refineries	15	14	14	14	13	12	15

- = Not available.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B29. U.S. and Foreign Refinery Output and Capacity for FRS Companies, Ranked by Total Energy Assets, and Industry, 1997
(Thousand Barrels per Day)

Refined Product Statistics [1]	FRS Companies					
	All FRS	Top Four	Five through Twelve[2]	All Other[2]	Total Industry	FRS Percent of Industry
United States						
Refinery Output Volume[3]	10,030	3,930	4,319	1,781	17,234	58.2
Percent Gasoline						
Reformulated/Oxygenated	15.1	25.9	9.8	4.3	14.7	59.7
Other	29.7	18.2	37.9	35.4	31.3	55.3
Percent Distillate	29.1	28.2	29.2	30.9	30.0	56.5
Percent Other	26.0	27.7	23.1	29.4	24.0	63.1
Refinery Capacity						
Years Change (Net)	-970	-43	88	-1,015	97	(5)
At Year End	9,507	3,412	4,106	1,989	16,129	58.9
Utilization Rate[4]	90.7	98.4	96.8	70.1	93.9	(5)
Foreign						
Refinery Output Volume[3]	4,311	3,822	-	489	-	(5)
Percent Gasoline	25.9	26.8	-	18.6	-	(5)
Percent Distillate	41.8	41.5	-	44.2	-	(5)
Percent Other	32.3	31.7	-	37.2	-	(5)
Refinery Capacity						
Years Change (Net)	-97	-150	-	53	985	(5)
At Year End	4,249	3,797	-	452	59,180	7.2
Utilization Rate[3]	92.2	90.5	-	107.6	-	(5)

[1]U.S. FRS and U.S. industry data include operations in Puerto Rico and the U.S. Virgin Islands. Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China.

[2]For foreign FRS, the "Five through Twelve" and "All Other" groups are combined to avoid disclosure.

[3]For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

[4]Defined as average daily crude runs at own refineries, for own account, and for account of others, divided by average daily crude distillation capacity.

[5]Not meaningful.

- = Not available.

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data, U.S. - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see Petroleum Supply Annual, 1996 and 1997. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy*, 1997 and 1998. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B30. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1991-1997

U.S. Dispositions	1991	1992	1993	1994	1995	1996	1997
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	568	231	196	268	365	400	581
U.S. Third-Party Sales							
Wholesale-Resellers	28,854	26,641	24,954	24,923	27,386	32,500	31,895
Company Operated Automotive Outlets	13,059	12,049	11,018	9,694	10,088	11,293	11,855
Outlets	22,459	23,061	21,917	20,948	20,494	21,725	20,517
Retail)	4,043	5,713	5,391	5,199	7,368	9,412	6,337
Total Third-Party Sales	68,415	67,464	63,280	60,764	65,336	74,930	70,604
Total Motor Gasoline Sales	68,983	67,695	63,476	61,032	65,701	75,330	71,185
Distillate Fuels							
Intersegment Sales	483	550	440	211	219	291	191
Third-Party Sales	35,052	33,370	32,624	30,357	30,201	41,327	36,771
Total Distillate Fuels Sales	35,535	33,920	33,064	30,568	30,420	41,618	36,962
Other Refined Products							
Intersegment Sales	4,435	4,671	4,213	3,824	3,952	4,124	3,322
Third-Party Sales	19,032	17,854	16,894	19,366	20,625	20,453	17,642
Total Other Refined Products Sales	23,467	22,525	21,107	23,190	24,577	24,577	20,964
Total U.S. Refined Products							
Intersegment Sales	5,486	5,452	4,849	4,303	4,536	4,815	4,094
Third-Party Sales	122,499	118,688	112,798	110,487	116,162	136,710	125,017
Total U.S. Refined Products Sales	127,985	124,140	117,647	114,790	120,698	141,525	129,111
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	18	9	9	9	11	12	18
U.S. Third-Party Sales							
Wholesale-Resellers	996	972	1,012	1,064	1,117	1,154	1,150
Company Operated Automotive Outlets	367	350	342	308	309	319	335
Outlets	734	740	731	736	680	653	615
Retail)	151	216	233	229	304	350	253
Total Third-Party Sales	2,248	2,277	2,318	2,338	2,411	2,476	2,353
Total Motor Gasoline Sales	2,267	2,286	2,327	2,347	2,422	2,488	2,371
Distillate Fuels							
Intersegment Sales	19	24	20	11	11	12	8
Third-Party Sales	1,328	1,340	1,380	1,381	1,363	1,550	1,464
Total Distillate Fuels Sales	1,347	1,364	1,400	1,392	1,374	1,562	1,473
Other Refined Products							
Intersegment Sales	212	232	240	226	222	209	254
Third-Party Sales	925	896	843	946	961	860	755
Total Other Refined Products Sales	1,137	1,128	1,082	1,172	1,183	1,069	1,008
Total U.S. Refined Products							
Intersegment Sales	249	264	269	246	245	232	280
Third-Party Sales	4,502	4,513	4,541	4,665	4,734	4,886	4,572
Total U.S. Refined Products Sales	4,751	4,778	4,810	4,911	4,979	5,119	4,852
Number of Active Automobile Outlets at Year End	Number of Automotive Outlets						
Company Operated	10,745	9,935	9,021	8,755	8,549	8,927	8,920
Lessee Dealers	19,891	19,334	18,588	16,385	15,861	15,247	12,874
Open Dealers	17,969	17,297	16,088	15,320	13,950	14,151	11,959
Total Outlets	48,605	46,566	43,697	40,460	38,360	38,325	33,753

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B31. Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1996-1997
(Million Barrels and Dollars per Barrel)

Product Distribution Channel	All FRS		Top Four		Five through Twelve		All Other	
	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Gasoline								
Intra-Company Sales								
1997	18.2	31.97	16.6	31.91	W	W	W	W
1996	11.9	33.50	10.5	33.88	0.4	31.91	1.0	30.19
Percent Change	52.2	-4.50	57.6	-5.80	40.2	1.10	0.6	9.00
Wholesale/Resellers								
1997	1,150.1	27.73	452.6	28.13	483.2	27.55	214.3	27.32
1996	1,154.3	28.16	396.0	29.20	460.9	28.25	297.4	26.63
Percent Change	-0.4	-1.50	14.3	-3.70	4.8	-2.50	-27.9	2.60
Dealer-Operated Outlets								
1997	614.7	33.38	272.7	34.06	307.7	33.24	34.3	29.20
1996	653.4	33.25	232.4	31.78	307.9	33.71	113.2	34.98
Percent Change	-5.9	0.40	17.3	7.20	-0.1	-1.40	-69.7	-16.50
Company-Operated Outlets								
1997	335.1	35.37	95.4	36.69	166.9	33.75	72.8	37.36
1996	318.7	35.43	79.9	36.78	154.9	34.46	83.9	35.94
Percent Change	5.2	-0.20	19.4	-0.20	7.8	-2.10	-13.3	3.90
Other [1]								
1997	253.1	25.03	59.4	28.52	113.6	23.47	80.1	24.67
1996	350.0	26.89	124.6	32.42	127.1	22.39	98.3	25.70
Percent Change	-27.7	-6.90	-52.3	-12.00	-10.6	4.80	-18.6	-4.00
Total Gasoline								
1997	2,371.2	30.02	896.7	30.94	1,071.9	29.72	402.5	28.78
1996	2,488.4	30.27	843.5	31.16	1,051.1	30.06	593.8	29.39
Percent Change	-4.7	-0.80	6.3	-0.70	2.0	-1.10	-32.2	-2.10
Distillate								
1997	1,472.8	25.10	567.6	24.99	617.8	25.22	287.3	25.04
1996	1,561.5	26.65	554.5	26.71	586.0	26.80	421.0	26.36
Percent Change	-5.7	-5.80	2.4	-6.40	5.4	-5.90	-31.8	-5.00
All Other Products								
1997	1,008.3	20.79	315.1	24.52	423.4	17.96	269.8	20.88
1996	1,068.7	23.00	339.8	23.59	369.1	21.97	359.8	23.49
Percent Change	-5.7	-9.60	-7.3	3.90	14.7	-18.20	-25.0	-11.10
Total Refined Products								
1997	4,852.2	26.61	1,779.5	27.90	2,113.1	26.05	959.6	25.44
1996	5,118.6	27.65	1,737.8	28.26	2,006.2	27.62	1,374.7	26.92
Percent Change	-5.2	-3.80	2.4	-1.30	5.3	-5.70	-30.2	-5.50

[1] Includes direct sales to industrial and commercial customers and sales to unconsolidated affiliates.

W = Data withheld to avoid disclosure.

Note: Sum of components may not equal total due to independent rounding.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B32. U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1991-1997
(Million Dollars)

Revenues and Costs	1991	1992	1993	1994	1995	1996	1997
Refined Product Revenues	127,985.0	124,140.0	117,647.0	114,790.0	120,698.0	141,525.0	129,111.0
Refined Product Costs							
Raw Materials Processed [1]	67,364.0	63,629.0	58,161.0	58,025.0	62,142.0	70,339.0	58,888.0
Refinery Energy Expense	5,544.0	5,363.0	5,636.0	4,702.0	4,101.0	5,480.0	5,005.0
Other Refinery Expense	9,053.0	9,040.0	8,889.0	8,854.0	8,854.0	9,882.0	8,364.0
Product Purchases	26,980.0	27,672.0	26,927.0	27,445.0	31,018.0	37,958.0	37,319.0
Other Product Supply Expense	4,097.0	3,739.0	4,153.0	3,432.0	3,432.0	4,072.0	3,849.0
Marketing Expense [2]	11,440.0	12,895.0	10,463.0	8,822.0	8,709.0	9,318.0	8,538.0
Total Refined Product Costs	124,478.0	122,338.0	114,229.0	111,280.0	118,256.0	137,049.0	121,963.0
Refined Product Margin	3,507.0	1,802.0	3,418.0	3,510.0	2,442.0	4,476.0	7,148.0
Refined Products Sold (million barrels)	4,750.6	4,777.6	4,810.0	4,911.0	4,978.8	5,118.6	4,852.2
Dollars per Barrel Margin [3]	0.74	0.38	0.71	0.70	0.50	0.90	1.50
Other Refining/Marketing Revenues [4]	9,861.0	10,007.0	10,614.0	10,586.0	10,449.0	10,731.0	9,693.0
Other Refining/Marketing Expenses							
DD&A	3,270.0	3,532.0	3,659.0	3,780.0	4,732.0	3,847.0	3,674.0
Other [5]	8,736.0	8,151.0	7,796.0	7,454.0	7,166.0	7,873.0	8,419.0
Total Other Expenses	12,006.0	11,683.0	11,455.0	11,234.0	11,898.0	11,720.0	12,093.0
Refining/Marketing Operating Income	1,362.0	126.0	2,577.0	2,862.0	993.0	3,487.0	4,748.0
Miscellaneous Revenue & Expense [6]	150.0	-115.0	207.0	289.0	-107.0	-101.0	204.0
Less Income Taxes	609.0	217.0	1,099.0	1,306.0	371.0	1,135.0	1,876.0
Refining/Marketing Net Income	903.0	-213.0	1,685.0	1,845.0	508.0	2,251.0	3,156.0

[1]Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.

[2]Excludes cost of marketing tires, batteries, and accessories (TBA).

[3]Dollars per barrel of refined product sold.

[4]Includes revenues from transportation services supplied (non-federally regulated), TBA sales, and miscellaneous.

[5]Includes general and administrative expenses, research and development costs, costs or transportation services supplied to other not included in raw material costs, and expenses for TBA.

[6]Includes other revenue and expense items, extraordinary items, and cumulative effect of accounting changes.

-- = Not applicable.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B33. U.S. Petroleum Refining/Marketing General Operating Expenses for FRS Companies, 1991-1997
(Million Dollars)

General Operating Expenses	1991	1992	1993	1994	1995	1996	1997
Raw Material Supply							
Raw Material Purchases	135,942	134,868	125,528	120,329	125,195	156,745	145,321
Other Raw Material Supply Expense	4,763	4,298	5,084	5,014	4,699	4,067	4,523
Total Raw Material Supply Expense	140,705	139,166	130,612	125,343	129,894	160,812	149,844
Less: Cost of Raw Materials Input To Refining	72,522	69,115	60,989	59,336	64,086	75,892	64,132
Net Raw Material Supply	68,183	70,051	69,623	66,007	65,808	84,920	85,712
Refining							
Raw Materials Input to Refining	72,522	69,115	60,989	59,336	64,086	75,892	64,132
Less: Raw Material Used as Refinery Fuel	3,591	3,392	3,592	2,933	2,588	3,922	3,798
Refinery Process Energy Expense	5,544	5,363	5,636	4,702	4,101	5,480	5,005
Other Refining Operating Expenses	9,912	9,943	9,803	9,658	9,551	10,631	9,101
Refined Product Purchases	26,980	27,672	26,927	27,445	31,018	37,958	37,319
Other Refined Product Supply Expenses	4,097	3,739	4,153	3,432	3,432	4,072	3,849
Total Refining	115,464	112,440	103,916	101,640	109,600	130,111	115,608
Marketing							
Cost of Other Products Sold	5,755	4,609	4,734	4,074	4,389	5,449	6,255
Other Marketing Expenses	11,440	12,895	10,463	8,822	8,709	9,318	8,538
Subtotal	17,195	17,504	15,197	12,896	13,098	14,767	14,793
Expense of Transport Services for Others	519	1,140	950	1,125	627	507	376
Total Marketing	17,714	18,644	16,147	14,021	13,725	15,274	15,169
Total U.S. Refining/Marketing Segment General Operating Expenses	201,361	201,135	189,686	181,668	189,133	230,305	216,489

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1991-1997
(Million Tons)

Reserves and Production Statistics	1991	1992	1993	1994	1995	1996	1997
Changes to U.S. Coal Reserves							
Beginning of Period	44,949	39,026	18,593	16,142	13,395	10,493	9,410
Changes due to:							
Leases/Purchases of Minerals-in-Place	-107	571	145	W	W	W	W
Corporate Mergers and Acquisitions	W	W	0	W	W	W	W
Other Reserve Changes	W	W	-325	-61	-699	8	-127
Production	290	252	197	180	165	169	163
Dispositions of Minerals-in-Place	-7,824	-18,576	-2,074	-2,591	-2,128	-1,150	-774
End of Period Reserves	38,219	20,787	16,142	13,381	10,493	9,542	8,498
Weighted Average Annual Production Capacity	327	291	236	201	184	192	215
Total United States							
FRS Companies' Reserves	38,219	20,787	16,142	13,381	10,493	9,542	8,498
FRS Companies' Production	290	252	197	180	165	169	163
U.S. Industry Production	996	994	941	1,029	1,028	1,059	1,085
Region							
East							
FRS Companies' Reserves	4,802	4,190	2,946	2,833	2,763	2,675	2,477
FRS Companies' Production	114	75	41	46	46	44	43
U.S. Industry Production	458	453	405	441	430	447	463
Midwest							
FRS Companies' Reserves	5,653	4,733	3,673	3,212	3,206	2,467	2,080
FRS Companies' Production	26	23	14	16	17	18	17
U.S. Industry Production	134	132	107	121	109	112	112
West							
FRS Companies' Reserves	27,764	11,864	9,523	7,336	4,524	4,400	3,940
FRS Companies' Production	149	154	143	118	103	107	104
U.S. Industry Production	405	409	429	467	489	500	511
Mining Method							
Underground							
FRS Companies' Reserves	10,136	8,127	6,068	5,479	5,337	4,571	3,880
FRS Companies' Production	123	84	53	59	62	59	51
U.S. Industry Production	407	407	351	399	396	409	420
Surface							
FRS Companies' Reserves	28,082	12,660	10,074	7,902	5,156	4,970	4,618
FRS Companies' Production	167	168	145	121	103	110	112
U.S. Industry Production	589	587	591	630	633	650	665

W = Data withheld to avoid disclosure.

Sources: Industry data - Energy Information Administration Form EIA-7A, see Coal Industry Annual 1997 (November 1998). FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Appendix C

Completed Foreign Direct Investment Transactions, 1996

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1996 Through December 1996 - Acquisitions and Divestitures

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
			Acquisitions			
Nova Corp(Canada) NGC Corp	Gas marketing	Chevron	Integrated petroleum operations	Asset acquisition	1,200.0	August
Forcenergy AB (Sweden) Forcenergy Inc.	Oil and gas exploration and production	Marathon Oil	Oil and gas exploration and production	Property acquisition	97.8	January
Canadian Occidental Petroleum (Canada) CXY Energy Offshore Inc	Oil and gas exploration and production	Shell Offshore Inc	Oil and gas exploration and production	Propert acqusition	50.2	December
Royal Dutch/Shell (Netherlands/UK) Shell Chemical Co.	Petrochemical operations	Louisian Land and Exploration Co.	Oil and gas exploration and production	Asset acquisition	50.0	August
Forcenergy AB (Sweden) Forcenergy Inc	Oil and gas exploration and production	Great Western Resources Inc	Oil and gas exploration and production	Merger	48.3	January
Norcen Energy Resources Ltd (Canada)	Oil and gas exploration and production	Flores & Rucks	Oil and gas exploration and production	Property acquisition	37.2	January
Sonatrach (Algeria) Anadarko Petroleum Corp	Oil and gas exploration and production	Panhandle Eastern Pipeline Co	Natural Gas transmission	Asset acquisition	36.0	March
Royal Dutch/Shell (Netherlands/UK) Shell Offshore Inc	Oil and gas exploration and production	Benton Oil and Gas Co	Oil and gas exploration and production	Equity acquisition	35.4	April
S A Louis Dreyfus et Cie (France) Louis Dreyfus Natural Gas Corp	Oil and gas exploration and production	Coastal Oil & Gas Co	Oil and gas exploration and production	Property acquisition	30.0	April
Forcenergy AB (Sweden) Forcenergy Inc	Oil and ga exploration an production	Unidentified	Unknown	Property acquisition	26.6	December
Norex Drilling Ltd (Bermuda) DI Industries	Drilling Services	Diamond M Offshore	Oil and gas exploration and production	Asset acquisition	26.0	November
Quest Oil & Gas (Canada) Gothic Energy Corp	Oil and gas exploration and production	Comstrock Resources Inc	Oil and gas exploration and production	Property acquisition	6.5	May
Forcenergy AB (Sweden) Forcenergy Inc.	Oil and gas exploration and production	Exxon Corp	Integrated petroleum operations	Property acquisition	Undisclosed	January
Royal Dutch/Shell (Netherlands/UK) Shell Offshore Inc	Oil and gas exploration and production	British Petroleum	Integrated petroleum operations	Property acquisition	Undisclosed	October

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1996 Through December 1996 - Acquisitions and Divestitures (continued)

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
Acquisitions (continued)						
Quest Oil & Gas (Canada) Gothic Energy Corp	Oil and gas exploration and production	Buttonwood Petroleum Inc	Oil and gas explorarion and production	Merger	Undisclosed	January
Divestitures						
Tosco Corp	Petroleum refining	**Investcorp S.A.** (Bahrain) Circle K Corp	Petroleum retailing, C-Store operations	Merger	444	May
Tosco Corp	Petroleum refining	**British Petroleum** (UK)	Integrated petroleum operations	Asset acquisition	235.0	February
CXY Energy Offshore Inc	Oil and gas exploration and production	**Royal Dutch/Shell** (Netherlands/UK) Shell Offshore	Oil and gas exploration and production	Property acquisition	50.2	December
Santa Fe Energy Resources	Oil and gas exploration and production	**S A Louis Dreyfus** (France) Louis Dreyfus Natural Gas Corp	Oil and gas exploration and production	Asset acquisition	16.0	October
Panaco	Oil and gas exploration and production	**Royal Dutch/Shell** (Netherlands/UK) Shell Oil	Integrated petroleum operations	Property acquisition	9.9	January
Texaco Inc	Integrated petroleum operations	**Royal Dutch/Shell** (Netherlands/UK) Shell Oil	Integrated petroleum operations	Property acquisition	Undisclosed	September
Delhi Gas Pipeline Corp	Natural gas gathering, transmission	**Royal Dutch/Shell** (Netherlands) Shell Western E&P	Oil and gas exploration and production	Asset acquisition	Undisclosed	April
ARCO	Integrated petroleum operations	**Royal Dutch/Shell** (Netherlands) Shell Land & Energy	Oil and gas exploration and production	Property acquisition	Undisclosed	June
RMS Energy	Oil and gas exploration and production	**Royal Dutch/Shell** (Netherlands) Shell Western E&P	Oil and gas exploration and production	Property acquisition	Undisclosed	June

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1996 Through December 1996 - Acquisitions and Divestitures (continued)

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
Divestitures (continued)						
EnerVest Management Co.	NA	**Royal Dutch/Shell** (Netherlands) Shell Western E&P	Oil and gas exploration and production	Property acquisition	Undisclosed	March

Sources: *The Wall Street Journal*, various issues, 1996 and 1997; *Business Week*, various issues; Company financial reports: annual reports to stockholders, annual reports on Securities and Exchange Commission (SEC) Form 10-K, and filing on SEC Schedule 13-D; *Oil and Gas Journal*, various issues, 1996 and 1997, Pennwell Publishing Company, Tulsa, OK; *The Merger Yearbook U.S./International Edition* 1997, Securities Data Company, New York, NY; *Oil and Gas Investor*, September 1996 and April 1997, Hart Publications, Inc., Denver, CO; *U.S. Oil Week*, various issues, 1996 and 1997, Capital Publishing Group, Alexandria, VA; Company press releases.

Table C2. Completed Transactions by Size in the Coal Industry from January 1996 Through December 1996 - Acquisitions

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
			Acquisitions			
ITOCHU Corp (Japan)	NA	Coastal Corp	Integrated petroleum, operations, coal	Asset acquisition	615	December
Ruhrkohle AG (Germany) RuhrAmerican	NA	Kerr McGee Corp	Integrated petroleum, operations, coal	Asset acquisition	Undisclosed	January

Sources: *The Merger Yearbook U.S./International Edition* 1997, Securities Data Company, New York, NY; *Coal,* various issues, 1996 and 1997, Maclean Hunter Publishing Co., Chicago, IL; Company press releases.

Glossary

Acquisition Costs: Direct costs and indirect costs incurred to acquire legal rights to deplete natural resources. Direct costs include costs incurred to obtain options to lease or purchase mineral rights and costs incurred for the actual leasing (e.g., lease bonuses) or purchasing of the rights. Indirect costs include such costs as: brokers' commissions and expenses; abstract and recording fees; filing and patenting fees; and costs of legal examination of title and documents.

Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. (See definition for Working Interest.) A distinction may be made between "gross" acreage and "net" acreage:

- **Gross.** All acreage covered by any working interest, regardless of the percentage of ownership in the interest.

- **Net.** Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.

Affiliate: An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified. The term "affiliate" includes any subsidiary or parent of the person specified.

Amortization: The depreciation, depletion, or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with nonproducing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration, and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Branded Product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Christmas Tree: The valves and fittings installed at the top of a gas or oil well to control and direct the flow of well fluids.

Coal Gasification: The process of converting coal into gas. The basic process involves crushing coal to a powder, which is then heated in the presence of steam and oxygen to produce a gas. The gas is then refined to reduce sulfur and other impurities. The gas can be used as a fuel or processed further and concentrated into chemical or liquid fuel.

Coal Liquefaction: A chemical process that converts coal into clean-burning liquid hydrocarbons, such as synthetic crude oil and methanol.

Coal Regions: The following regional definitions are used to report domestic coal reserves, production, and other operating statistics.

- **Eastern Region.** Consists of the Northern Appalachian Coal Basin. The following States comprise the Eastern Region: Alabama, Georgia, Ohio, Maryland, Mississippi, Pennsylvania, Virginia, Tennessee, North Carolina, West Virginia, and Eastern Kentucky.

- **Midwest Region.** Consists of the Illinois and Michigan Coal Basins. The following States comprise the Midwest Region: Illinois, Indiana, Michigan, and Western Kentucky.

- **Western Region.** Consists of the Northern Rocky, Southern Rocky, Western Interior, and West Coast Coal Basins. The following States comprise the Central Western Region: Alaska, Arizona, Arkansas, California, Colorado, Idaho, Iowa, Kansas, Louisiana, Missouri, Montana, New Mexico, North Dakota, Oklahoma, Oregon, Texas, South Dakota, Utah, Washington, and Wyoming.

Company Automotive (Retail) Outlet: Any retail outlet selling motor fuel under a reporting company brand name. (See definition for Branded Product.)

- **Company Operated.** A company retail outlet which is operated by salaried or commission personnel paid by the reporting company.

- **Lessee.** An independent marketer who leases the station and land and has use of tanks, pumps, signs, etc. A lessee dealer typically has a supply agreement with a refiner or a distributor and purchases products at dealer tank wagon prices. The term "lessee dealer" is limited to those dealers who are supplied directly by a refiner or any affiliate or subsidiary company of a refiner. "Direct supply" includes use of commission agent or common carrier delivery.

- **Open.** An independent marketer who owns or leases (from a third party who is not a refiner) the station or land of a retail outlet and has use of tanks, pumps, signs, etc. An open dealer typically has a supply agreement with a refiner or a distributor and purchases products at or below dealer tank wagon prices.

Contribution to Net Income: The FRS segment equivalent of net income. However, many consolidated items of revenue and expense are not allocated to the segments, and therefore they are not equivalent in a strict sense. The largest item not allocated to the segments is interest expense since this is regarded as a corporate-level item for FRS purposes.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For FRS reporting, volumes reported as crude include:

- Liquids technically defined as crude oil.

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are commingled with the crude stream without being separately measured.

- Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production and reserves are reported as liquid equivalents at the surface (excluding base sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, corrected to 60 degrees Fahrenheit.

Where a State regulatory agency specifies a definition of crude oil which differs from that set forth above for statistical purposes, the State definition should be followed.

DD&A: Abbreviation for depreciation, depletion and amortization.

Deferred Taxes: Taxes accrued and reflected as an expense in a company's income statement, but not payable to the taxing authority in that time period. These taxes are accrued to compensate for an understatement of income tax expense which would occur if only the tax currently due to the taxing authority were reflected as the total income tax expense.

Depletion: A term for either (1) a periodic assignment to expense of recorded amounts or (2) an allowable income tax deduction that is related to the exhaustion of mineral reserves. Depletion is included as one of the elements of amortization. When used in that manner, depletion refers only to book depletion (see definition for Amortization).

- **Book.** The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.

- **Tax-cost.** A deduction (allowance) under U.S. Federal Income taxation normally calculated under a formula whereby the adjusted basis of the mineral property is multiplied by a fraction, the numerator of which is the number of units of minerals sold during the tax year and the denominator of which is the estimated number of units of unextracted minerals remaining at the end of the tax year plus the number of units of minerals sold during the tax year.

- **Tax-percentage (or Statutory).** A deduction (allowance) allowed to certain mineral producers under U.S. Federal income taxation calculated on the basis of a specified percentage of gross revenue from the sale of minerals from each mineral property not to exceed the lesser of 50 percent of the taxable income from the property computed without allowance for depletion. (There are also other limits on percentage depletion on oil and gas production.) The taxpayer is entitled to a deduction representing the amount of tax-cost depletion or percentage (statutory) depletion, whichever is higher.

- **Excess Statutory Depletion.** The excess of estimated statutory depletion allowable as an income tax deduction over the amount of cost depletion otherwise allowable as a tax deduction, determined on a total enterprise basis.

Depreciation: See definition for Amortization.

Development: The preparation of a specific mineral deposit for commercial production; this preparation includes construction of access to the deposit and of facilities to extract the minerals. The development process is sometimes further distinguished between a preproduction stage and a current stage, with the distinction being made on the basis of whether the development work is performed before or after production from the mineral deposit has commenced on a commercial scale.

Development Costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. More specifically, development costs, and also depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves;

- Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and utility waste disposal systems; and

- Provide improved recovery systems.

Distillate: A general classification for one of the petroleum fractions produced in conventional distillation operations. Included are kerosene and products known as heating oils and diesel fuels, specifically: No. 1, No. 2, and No. 4 Fuel Oils and No. 1, No. 2, and No. 4 Diesel Fuels.

Domestic Operations: Domestic operations are those operations located in the United States.

- The United States is defined as the 50 States, including their offshore territorial waters, the District of Columbia, U.S. commonwealth territories, and protectorates.

Drilling: The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids).

- **Exploratory.** Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.

- **Developmental.** Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.

- **Directional.** Drilling that is deliberately made to depart significantly from the vertical.

Drilling and Equipping of Wells: The drilling and equipping of wells through completion of the "christmas tree."

Dry-Hole Charge: The charge-off to expense of a previously capitalized cost upon the conclusion of an unsuccessful drilling effort.

Equity in Earnings of Unconsolidated Affiliates: A company's proportional share (based on ownership) of the net earnings or losses of an unconsolidated affiliate.

Exploration: The identification of areas that may warrant examination and to examine specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property.

Exploration Costs: Costs, including depreciation and applicable operating costs, of support equipment and facilities and other costs directly identifiable with exploration activities, such as:

- Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these costs are sometimes referred to as geological and geophysical, or "G&G" costs.

- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.

- Dry hole contributions and bottom hole contributions. Costs of drilling and equipping exploratory wells.

- Costs of drilling exploratory-type stratigraphic test wells.

Extraordinary Item: Income and expense items associated with events and transactions that possess a high degree of abnormality and are of a type that would not reasonably be expected to recur in the foreseeable future.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and / or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Footage Drilled: Total footage for wells in various categories, as reported for any specified period, includes (1) the deepest total depth (length of well bores) of all wells drilled from the surface, (2) the total of all bypassed footage drilled in connection with reported wells, and (3) all new footage drilled for directional "sidetrack" wells. Footage reported for directional "sidetrack" wells does not include footage in the common bore, which is reported as footage for the original well. In the case of old wells drilled deeper, the reported footage is that which was drilled below the total depth of the old well.

- **Deepest Total Depth.** The deepest total depth of a given well is the distance from a surface reference point (usually the Kelly bushing) to the point of deepest penetration measured along the well bore. If a well is drilled from a platform or barge over water, the depth of the water is included in the total length of the well bore.

- **Sidetrack Drilling.** This is a remedial operation that results in the creation of a new section of well bore for the purpose of (1) detouring around junk, (2) redrilling lost hole, or (3) straightening key seats and crooked holes. Directional "sidetrack" wells do not include footage in the common bore which is reported as footage for the original well.

Foreign Access: Refers to proved reserves of crude (including lease condensate) and natural gas liquids applicable to long-term supply agreements with foreign governments or authorities in which the company acts as producer.

Foreign Operations: These are operations that are located outside the United States. Determination of whether an enterprise's mobile assets, such as offshore drilling rigs or ocean-going vessels, constitute foreign operations should depend on whether such assets are normally identified with operations located outside the United States.

Foreign operations are segregated into the following areas for FRS reporting purposes:

- **OECD Europe.** Includes Austria, Belgium, Denmark, Finland, France, the Federal Republic of Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

- **Former Soviet Union (FSU) and East Europe.** The Baltic States of Estonia, Latvia, and Lithuania, as well as Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgystan, Moldova, Russia, Tajikstan, Turkmenistan, Ukraine, Uzbekistan, Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, and Yugoslavia.

- **Middle East.** Includes Saudi Arabia, the United Arab Emirates, Iraq, Iran, Kuwait, the Iraq-Saudi Arabia Neutral Zone, Qatar, Dubai, Bahrain, Oman, Yemen, Syria, Jordan, and Israel.

- **Canada.**

- **Africa** (the African continent).

- **Other Eastern Hemisphere.** Areas eastward of the Greenwich prime meridian to 180 degrees longitude and not included in other specified domestic or foreign classifications.

- **Other Western Hemisphere.** Areas westward of the Greenwich prime meridian to 180 degrees longitude not included in other domestic or foreign classifications.

Funds From Operations: Calculated by adding noncash charges back to net income or contribution to net income. Deferred taxes and depreciation, depletion, and amortization (DD&A) are the largest noncash charges.

Funds, Total Sources of: The total source of funds including net income plus noncash charges such as DD&A and deferred taxes, issuances of stocks and bonds, and proceeds from the sale or property, plant, and equipment. The concept is similar to cash flow generated, but does not attempt to account for changes in working capital items. Thus, for example, an inventory buildup or drawdown would not be accounted for under the “funds” concept since both cash and inventory are items of working capital.

Geological and Geophysical (G&G) Costs: Costs incurred in making geological and geophysical studies, including, but not limited to, costs incurred for salaries, equipment, obtaining rights of access, and supplies for scouts, geologists, and geophysical crews.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in either the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (e.g., methane, a constituent of natural gas) to the very heavy and very complex.

Improved Recovery: The operation whereby crude oil or natural gas is recovered using any method other than those that rely primarily on the use of natural reservoir pressure, gas lift, or a pump.

Intangible Drilling and Development Costs (IDC): Costs incurred in preparing well locations, drilling and deepening wells, and preparing wells for initial production up through the point of installing control valves. None of these functions, because of their nature, have salvage value. Such costs would include labor, transportation, consumable supplies, drilling tool rentals, site clearance, and similar costs.

Investment and Advances to Unconsolidated Affiliates: The balance sheet account representing the cost of investments and advances to unconsolidated affiliates. Generally, affiliates which are less than 50 percent owned by a company may not be consolidated into the company's financial statements.

Lease Bonus: An amount paid by a lessee to a lessor as consideration for granting a lease, usually as a lump sum; this payment is in addition to any rental or royalty payments.

Lease Equipment: All equipment located on the lease except the well and the complete christmas tree installation.

Lifting Costs: The costs associated with the extraction of a mineral reserve from a producing property. (See definition for Production Cost.)

Mineral: Any of the various naturally occurring substances (such as coal, crude oil, metals, natural gas, salt, sand, stone, sulfur, and water) usually obtained from the earth. The term is used to include all wasting, i.e., nonregenerative, inorganic substances that are extracted from the earth.

Mineral Interests in Properties (hereinafter referred to as Properties): These include fee ownership or a lease, concession, or other contractual interest representing the right to extract minerals subject to such terms as may be imposed by the conveyance of those interests. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as "producer" of the underlying reserves, but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Mineral Lease: An agreement wherein a mineral interest owner (lessor) conveys to another party (lessee) the rights to explore for, develop, and produce specified minerals. The lessee acquires a working interest and the lessor retains a nonoperating interest in the property, referred to as the royalty interest, each in proportions agreed upon.

Mineral Rights: The ownership of the minerals beneath the earth's surface with the right to remove them. Mineral rights may be conveyed separately from surface rights.

Mining: Any activity directed to the extraction of ore and associated rock. Included are open pit work, quarrying, augering, alluvial dredging, and combined operations, including surface and underground operations.

Minority Interest in Income: The proportional share of the minority ownership's interest (less than 50 percent) in the earnings or losses of the consolidated subsidiary.

Subsidiaries are generally fully consolidated when a share of ownership between 51 percent and 100 percent is held by the parent. In consolidation, 100 percent of revenues, expenses, assets, etc. are included in the financial statements even though, for example, the subsidiary is only 80 percent owned by the parent company. In such cases, the consolidated balance sheet must have a caption on the right-hand side titled something like "minority interests in consolidated affiliates," and the income statement must have a similar line to reduce net income to the pro rata (80 percent in this example) share of the consolidated subsidiary's net income.

Motor Gasoline (Finished): A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, that has been blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline, as given in ASTM Specification D439 or Federal Specification VV-G-l690B, includes a range in distillation temperatures from 122 to 158 degrees Fahrenheit at the 10-percent recovery point and from 365 to 374 degrees Fahrenheit at the 90-percent recovery point. Motor gasoline includes reformulated motor gasoline, oxygenated motor gasoline, and other finished motor gasoline. Blendstock is excluded until blending has been completed.

- **Reformulated Motor Gasoline.** Gasoline reformulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211K of the Clean Air Act.

- **Oxygenated Gasoline.** Gasoline formulated for use in motor vehicles that has an oxygen content of 1.8 percent or higher, by weight. Includes gasohol.

- **Other Finished Gasoline.** Motor Gasoline not included in the oxygenated or reformulated gasoline categories.

Motor Gasoline, Finished Gasohol: A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol), limited to 10 percent by volume of alcohol.

Motor Gasoline, Finished Leaded: Contains more than 0.05 gram of lead per gallon or more than 0.005 gram of phosphorus per gallon. Premium and regular grades are included, depending on the octane rating. Includes leaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasoline is excluded.

Motor Gasoline, Finished Unleaded: Contains not more than 0.05 gram of lead per gallon and not more than 0.005 gram of phosphorus per gallons. Premium and regular grades are included, depending on the octane rating. Includes unleaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded.

MTBE (Methyl tertiary butyl ether) (CH3)3C)CH: An ether intended for motor gasoline blending. (See definition for Oxygenates.)

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes, and pentanes. Typical nonhydrocarbon bases which may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances.

Natural gas, based on the type of occurrence in the reservoir, is classified by two categories, as follows:

- **Non-Associated Gas** is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

- **Associated/Dissolved Gas** is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas that is in solution with crude oil in the reservoir at reservoir conditions.

Statistical data pertaining to natural gas production and reserves are reported in units of 1,000,000 cubic feet (i.e., MMCF) at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit for FRS purposes.

Natural Gas Liquids (NGL): Natural gas liquids are those portions of reservoir gas which are liquefied at the surface in lease separators, field facilities, or gas processing plants. Natural gas liquids include but are not limited to: ethane, propane, butanes, pentanes, natural gasoline, and condensate.

Net Investment in Place: The sum of net property, plant, and equipment (PP&E) plus investment and advances to unconsolidated affiliates.

Nonbranded Product: Any refined petroleum product that is not a branded product.

Nuclear Fuel Operations: All nuclear fuel operations, excluding reactor and reactor component manufacturing or containment construction. Includes exploration and development; mining; milling; conversion; enrichment; fabrication; reprocessing; and spent fuel storage.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

If a State agency uses a different basis for classifying onshore and offshore areas, the State classification should be used. (Cook Inlet in Alaska is classified as offshore.)

Oil Shale: A sedimentary rock containing kerogen, a solid organic material.

Operating Expenses: Segment expenses related both to revenue from sales to unaffiliated customers and revenue from intersegment sales or transfers, excluding loss on disposition of property, plant, and equipment; interest expenses and financial charges; foreign currency translation effects; minority interest; and income taxes.

Operating Income: Operating revenues less operating expenses. Excludes items of other revenue and expense, such as equity in earnings of unconsolidated affiliates, dividends, interest income and expense, income taxes, extraordinary items, and cumulative effect of accounting changes.

Operating Revenues: Segment revenues both from sales to unaffiliated customers (i.e., revenue from customers outside the enterprise as reported in the company's consolidated income statement) and from intersegment sales or transfers, if any, of product and services similar to those sold to unaffiliated customers, excluding equity in earnings of unconsolidated affiliates; dividend and interest income; gain on disposition of property, plant, and equipment; and foreign currency translation effects.

Other Energy Operations: Energy operations not included in Petroleum or Coal. Other Energy includes nuclear, oil shale, tar sands, coal liquefaction and gasification, geothermal, solar, and other forms of nonconventional energy.

Oxygenates: Any substance which, when added to gasoline, increases the amount of oxygen in that gasoline blend. Through a series of waivers and interpretive rules, the Environment Protection Agency (EPA) has determined the allowable limits for oxygenates in unleaded gasoline. The “Substantially Similar” Interpretive Rules (56 FR (February 11, 1991)) allows blends of aliphatic alcohols other than methanol and aliphatic ethers, provided the oxygen content does not exceed 2.7 percent by weight. The “Substantially Similar” Interpretive Rules also provide for blends of methanol up to 0.3 percent by volume exclusive of other oxygenates, and butanol or alcohols of a higher molecular weight up to 2.75 percent by weight. Individual waiver pertaining to the use of oxygenates in unleaded gasoline have been issued by the EPA. They include:

- **Fuel Ethanol.** Blends of up to 10 percent by volume anhydrous ethanol (200 proof) (commonly referred to as the “gasohol waiver”).

- **Methanol.** Blends of methanol and gasoline-grade tertiary butyl alcohol (GTBA) such that the total oxygen content does not exceed 3.5 percent by weight and the ratio of methanol to GTBA is less than or equal to 1. It is also specified that this blended fuel must meet American Society for Testing and Materials (ASTM) volatility specifications (commonly referred to as the “ARCO” waiver).

  Blends of up to 5.0 percent by volume methanol with a minimum of 3.5 percent by volume cosolvent alcohols having a carbon number of 4 or less (i.e., ethanol, propanol, butanol, and / or GTBA). The total oxygen must not exceed 3.7 percent by weight, and the blend must meet ASTM volatility specifications as well as phase separation and purity specifications (commonly referred to as the “DuPont” waiver).

- **MTBE (Methyl tertiary butyl ether).** Blends up to 15.0 percent by volume MTBE which must meet the ASTM D4814 specifications. Blenders must take precautions that the blends are not used as base gasolines for other oxygenated blends (commonly referred to as the “Sun” waiver).

PP&E, Additions to: The current year's expenditures on property, plant, and equipment (PP&E). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS will be a function of each reporting company's policy.

PP&E, Net: The original cost of property, plant, and equipment (PP&E), less accumulated depreciation.

Petroleum: Hydrocarbon mixtures broadly defined to include crude oil, lease condensate, natural gas, products of natural gas processing plants (plant products), refined products, and semifinished products and blending materials.

Pipelines, Rate Regulated: FRS establishes three pipeline segments: crude/liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all Federally or State rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option, intrastate pipeline operations may be included in the U.S. Refining/ Marketing Segment **if:** they would comprise less than 5 percent of U.S. Refining/Marketing Segment net PP&E, revenues, and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PP&E reported for the U.S. Refining/Market Segment.

Primary Recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure (energy or gravity).

Primary Transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Producing Property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Production, Natural Gas Liquids: Production of natural gas liquids is classified as follows:

- **Contract Production.** Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.
- **Leasehold Production.** Natural gas liquids produced, extracted, and credited to a company's interest.
- **Contract Reserves.** Natural gas liquid reserves corresponding to the contract production defined above.
- **Leasehold Reserves.** Natural gas liquid reserves corresponding to the leasehold production defined above.

Production, Oil and Gas: The lifting of the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

- **Gross Company-Operated Production.** Total production from all company-operated properties, including all working and nonworking interests.

- **Net Working Interest Production.** Total production accruing to the reporting company's working interests less royalty oil and volumes due others.

Production Costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs):

- Costs of labor to operate the wells and related equipment and facilities.

- Repair and maintenance costs.

- The costs of materials, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities.

- The costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

- The costs of severance taxes.

Depreciation, depletion, and amortization (DD&A) of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Production costs include the following subcategories of costs:

- Well operations and maintenance

- Well workovers

- Operating fluid injection and improved recovery programs

- Operating gas processing plants

- *Ad valorem* taxes

- Production or severance taxes

- Other, including overhead.

Research and Development: Basic and applied research in the sciences and engineering and the design and development of prototypes and processes, excluding quality control, routine product testing, market research, sales promotion, sales service, research in the social sciences or psychology, and other non-technological activities or technical services.

Reserves, Change in: For FRS reporting, the following definitions should be used for changes in reserves.

- **Revisions of Previous Estimates.** Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.

- **Improved Recovery.** Changes in reserve estimates resulting from application of improved recovery techniques shall be separately shown, if significant. If not significant, such changes shall be included in revisions of previous estimates.

- **Purchases or Sales of Minerals-in-Place.** Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.

- **Extensions, Discoveries, and Other Additions.** Additions to an enterprise's proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Reserves (Coal): Coal reserve estimates comprising the demonstrated coal reserve base include only proved (measured) and probable (indicated).

- **Proved (Measured) Reserves.** Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.

- **Probable (Indicated) Reserves.** Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on geologic evidence. The sites available are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Reserves, Net: Includes all proved reserves associated with the company's net working interests. (See definition for Working Interest.)

Reserves, Proved (Oil and Gas): The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by one or more of: actual production; conclusive formation test; core analysis; and/or electric or other log interpretations. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limited of the reservoir.

Volumes of oil and gas placed in underground storage are not to be considered proved reserves; but should be classified as inventory.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

For natural gas, an appropriate reduction in the reservoir gas volume is made to cover the removal of the liquefiable portions of the gas and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. If the liquefiable portions of the gas are not separately estimated, they need not be separately stated for FRS reporting purposes.

Reservoir: A porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons (oil and / or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Residual Fuel Oil: The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and 975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; No. 6, which includes Bunker C fuel oil, and is used for commercial and industrial heating, electricity generation, and to power ships.

Royalty: A contractual arrangement providing a mineral interest that gives the owner a right to a fractional share of production or proceeds therefrom, that does not contain rights and obligations of operating a mineral property, and that is normally free and clear of exploration, developmental, and operating costs, except production taxes.

Short Ton: A unit of weight that equals 2,000 pounds.

Support Equipment and Facilities: These include, but are not limited to, seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

Tangible Development Costs: Cost incurred during the development stage for access, mineral-handling, and support facilities having a physical nature. In mining, such costs would include tracks, lighting equipment, ventilation equipment, other equipment installed in the mine to facilitate the extraction of minerals, and supporting facilities for housing and care of work forces. In the oil and gas industry, tangible development costs would include well equipment (such as casing, tubing, pumping equipment, and well heads), as well as field storage tanks and gathering systems.

Tar Sands: Naturally occurring bitumen-impregnated sands that yield mixtures of liquid hydrocarbon and that require further processing other than mechanical blending before becoming finished petroleum products.

Timing Differences: Differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. Timing differences originate in one period and reverse or "turn around" in one or more subsequent periods. Some timing differences reduce income taxes that would otherwise be payable currently; others increase income taxes that would otherwise be payable currently.

Transfer Price: The monetary value assigned to products, services, or rights conveyed or exchanged between related parties, including those occurring between units of a consolidated entity.

Uncompleted Wells, Equipment, and Facilities Costs: The costs incurred to (1) drill and equip wells that are not yet completed, and (2) acquire or construct equipment and facilities that are not yet completed and installed.

Undeveloped Property: Refers to a mineral property on which development wells or mines have not been drilled or completed to a point that would permit the production of commercial quantities of mineral reserves.

Uranium Oxide: A yellow or brown powder produced from naturally occurring uranium minerals as a result of milling uranium ore or processing uranium-bearing solutions. Synonymous with "yellowcake," U_3O_8, or uranium concentrate.

Well: A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.

Wells are classified as (1) oil wells; (2) gas wells; (3) dry holes; (4) stratigraphic test wells; or (5) service wells. The latter two types of wells are not counted for FRS reporting.

Oil wells, gas wells, and dry holes are classified as exploratory wells or development wells. Exploratory wells are subclassified as (1) new-pool wildcats; (2) deeper-pool tests; (3) shallow-pool test; and (4) outpost (extension) tests. Well classifications reflect the status of wells after drilling has been completed.

- **Completion.** The term refers to the installation of permanent equipment for the production of oil or gas.
- **Development Well.** A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
- **Dry Hole.** An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
- **Exploratory Well.** A well that is not a development well, a service well, nor a stratigraphic test as those items are defined elsewhere.
- **Oil Well.** A well completed for the production of crude oil from at least one oil zone or reservoir.

Wellhead Price: The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.

Working Interest: An interest in a mineral property that entitles the owner of that interest to all of a share of mineral production from the property, usually subject to a royalty.

A working interest permits the owner to explore, develop, and operate the property. The working interest owner bears the costs of exploration, development, and operation of the property and, in return, is entitled to a share of the mineral production from the property or to a share of the proceeds therefrom. It may be assigned to another party in whole or in part, or it may be divided into other special property interests.

- **Gross Working Interest.** The reporting company's working interest plus the proportionate share of any basic royalty interest or overriding royalty interest related to the working interest.
- **Net Working Interest.** The reporting company's working interest not including any basic royalty or overriding royalty interests.