Energy Finance

# Performance Profiles of Major Energy Producers 1998

**January 2000**

# Contacts

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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 at http://www.eia.doe.gov/emeu/perfpro/wk1/frsdata.html. They are also available on a 3.5-inch high-density diskette. These data cover the years 1977 through 1998, 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.*

To receive the Financial Reporting System 1977-1998 diskette, please contact Greg Filas at (202) 586-1347, FAX (202) 586-9753, or INTERNET email 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 1998.")

There were 11 new survey respondents added to the group of FRS companies in 1998, a 50-percent increase over the prior year. The large increase is due to modifications made to the FRS survey selection criteria. Recently, the Energy Information Administration (EIA) has seen a significant drop in the FRS survey coverage of the U.S. refining industry, as well as evidence of newly emerging patterns of U.S. refining industry organization. A number of FRS companies have sold their U.S. refining assets, including assets previously committed to joint ventures. These rapid industry changes would have substantially reduced the ability of EIA's FRS to meet its legislative requirement to provide "… a statistically accurate profile …" of the U.S. refining line of commerce for the 1998 reporting year and beyond, unless the respondent company selection criteria for Form EIA-28 were modified. The new selection criteria allow for the inclusion of large, U.S. non-integrated refining companies in the FRS survey, resulting in an FRS survey coverage of 85 percent of domestic refining capacity during 1998, instead of the 60 percent (or less) industry representation anticipated under the previous respondent company selection criteria.

The economic performance of the FRS 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.

*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[Note 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 which may result in new or increased opportunities for independent oil and gas producers and fast-growing petroleum refiners in the United States are also explored.

This edition of *Performance Profiles* reviews financial and operating data for the calendar year 1998.

Although the focus is on 1998 activities and results, important trends prior to that time and emerging issues relevant to U.S. energy company operations are also discussed.

The analyses in this report are based on detailed financial and operating data and information submitted each year to the EIA on Form EIA-28, the Financial Reporting System. 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 is 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 P.L. 95-91, 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/pubs.html ) are intended for use by the U.S. Congress, government agencies, industry analysts, and the general public.

Additional information about the Form EIA-28 can also be found at http://www.eia.doe.gov/emeu/finance/page1a.html. 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/glossary.html.

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# Preface Endnotes

[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. Challenges and opportunities in 1998 included:

- oil prices that fell to a 25-year low in December
- a second consecutive year of abnormally high petroleum inventories
- solid economic growth in most industrialized nations but recessions of varying severity in several Asia Pacific nations
- a second consecutive winter with generally milder weather and lessened heating demand
- lower natural gas prices in the United States and abroad
- additional openings of oil and gas producing nations to foreign investment
- continued advances in exploration and production technology
- deregulation of electricity markets.

The Energy Information Administration (EIA) maintains the Financial Reporting System (FRS) in order to analyze the extent to which these and other developments have affected energy industry financial and operating performance, strategies, and industry structure.

Through Form EIA-28, major U.S. energy companies annually report to the FRS (see the box entitled "The FRS Companies in 1998" 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.

## Oil Market Turmoil Produces Earnings Collapse

The FRS companies' total net income in 1998 was down 61 percent from 1997's all-time record level. The primary sources of earnings collapse were low oil and gas prices, declining U.S. oil production, and reduced sales of natural gas in the United States which drove income from the FRS companies' upstream operations to 12 percent of the prior-year level.

U.S. downstream operations moderated the devastation in upstream financial results. Refining and marketing performed well in 1998, but not for the usual reasons. Usually, when crude oil prices fall steeply, refined product prices tend to lag, yielding higher price-cost margins. Also, sales volumes rise in response to lower product prices. Wider margins and higher sales yield better bottom-line results.

The year 1998 was different for the FRS companies. Excessive buildups of petroleum inventories, stemming from supply-demand imbalances in oil markets in 1998 (and in 1997, as well), led to a squeeze on refiners' price-cost margins. Also, the volume of refined products sold by FRS refiners with ongoing downstream operations (that is, companies that were in the FRS group in 1997 and 1998) was down, as this group sold three refineries in 1998. (Note that, in 1998, 11 refiners were added to the FRS survey - see Preface.) These refiners were able to offset the margin squeeze by cutting operating expenses while their revenues from convenience stores and other non-fuel services were up. The result for ongoing FRS refiners/marketers was a 50-percent increase in income from U.S. refining and marketing operations and a rise in the profitability of these operations to a 1990’s high.

Cash flow (i.e., cash internally generated by operations) was, for FRS companies who reported in both 1997 and 1998, at the lowest level since 1986, the year of the last oil price collapse. Nearly all of the fall in cash flow in 1998 was traceable to declines in oil and gas production revenues.

Cash flow is the main source of funds for the FRS companies, with debt issuance a distant second. Until 1998, the FRS companies' capital expenditures were always less than cash flow, averaging about 86 percent of cash flow. However, in 1998, the FRS companies' capital expenditures far outran cash flow.

## Capital Expenditures at Second-Highest Level Despite Oil Price Collapse

The FRS companies' capital expenditures in 1998 totaled $75 billion, some $27 billion greater than cash flow and second only to expenditures in the mega-merger year of 1984, when Chevron merged with Gulf Oil, Mobil merged with Superior Oil, and Texaco merged with Getty Oil. Capital expenditures were 156 percent of cash flow which was far more than the 86 percent average noted in the previous paragraph. Several factors led to the upswing in expenditures despite the collapse in oil prices.

Mergers and acquisitions accounted for $21 billion of capital expenditures in 1998. Of the six FRS company acquisitions that exceeded $1 billion, five involved oil and gas production assets. These latter transactions were planned when oil prices were in the $16 to $21 per barrel trading range typical of most of the 1990's and were implemented in early 1998 well before the oil price collapse had completely unfolded.

Another factor that buoyed capital expenditures was that, despite the oil price collapse, FRS companies tended to push ahead with those ongoing projects which have relatively long lead times. For example, the number of development wells (i.e., wells intended for production of oil and gas) completed by the FRS companies in the North Sea hit a record high. The lead times for North Sea projects typically span more than a year and involve considerable commitment of outlays, characteristics which make spending for these projects somewhat unresponsive to short-run oil price volatility. Similarly, development of oil fields in Alaska tends to share these characteristics. The FRS companies involved in this region focused on offsetting the decline in oil production from the giant, but mature, Prudhoe Bay field on Alaska's North Slope through development of new fields and development of smaller satellite fields near established producing areas.

The search for new oil and gas fields continued as all but one region (Europe) registered an increase in exploration expenditures by the FRS companies in 1998. Offshore locales accounted for the bulk of increased spending for exploratory activity. Recent success in finding large fields in deep waters and opportunities to apply advancing technologies have made a number of offshore areas attractive investment targets. The west coast of Africa and the Gulf of Mexico stood out in these respects in 1998.

The Other Western Hemisphere region (i.e., South America and Central America), of which Venezuela is a part, registered the largest increase in the FRS companies' combined exploration and development expenditures (excluding the effects of mergers and acquisitions) between 1997 and 1998, with the six FRS companies involved in Venezuelan joint ventures accounting for most of the increase. As of 1998, the government of Venezuela has allowed foreign companies to invest in oil and gas projects, mainly through joint ventures with the state-owned energy company Petroleos de Venezuela and its subsidiaries. The projects involve production and processing of unusually heavy crude oils, rejuvenating production from existing fields, and exploration and development of new fields both onshore and offshore.

## Will Balance Sheet Turmoil Slow Oil and Gas Resource Development ?

The huge disparity between capital expenditures and cash flow of $27 billion in 1998 required massive adjustments by the FRS companies in their deployment of capital. The companies responded by increasing their debt loads through additional long-term borrowing and cutbacks in debt reduction. The FRS companies realized a record level of cash through asset sales, as low oil prices and cash shortfalls may have accelerated planned divestitures. Shareholders suffered as the FRS companies cut their cash dividends and stock repurchases. Lastly, the FRS companies drew down their cash balances by over $4 billion.

These adjustments ran counter to recent trends in the FRS companies' deployment of capital. During the 1990's they had been reducing the role of debt in their balance sheets. They managed to reduce the ratio of their long-term debt to stockholders' equity, an often-used measure of the role of debt, from 60 percent in 1992 to less than 40 percent in 1997. However, added debt in 1998 hiked this ratio to 50 percent.

Cutbacks in shareholder payouts in 1998 represented another break in trend. Until 1998, the FRS companies had been modestly, but steadily, increasing dividends to shareholders for the previous 10 years. Reductions in dividends are usually unwelcome events to shareholders and can have adverse effects on a company's market value. Also, the drawdown of cash reserves of $4.4 billion in 1998 was well above the average of $1.0 billion of the previous 10 years.

Are the FRS companies likely to cut future investment spending in favor of restoring customary patterns of capital deployment? A survey of oil and gas producers' capital expenditure plans taken in early 1999 by Salomon Smith Barney, a financial services company, indicated that expenditures for oil and gas exploration and development might be substantially trimmed in 1999. For the FRS companies, the survey results showed a 28-percent reduction in planned 1999 U.S. exploration and development expenditures and a 7-percent reduction abroad from 1998 levels. Further, the FRS data show that, in 1998, the number of exploratory wells initiated in U.S. onshore locales by FRS companies was down a stunning 36 percent. This latter result does not bode well for near-term U.S. onshore oil and gas development.

The portents of these results should be set against the fact that since January 1999, oil prices have risen from $10 per barrel to $22 per barrel in October. Also, in response to cutbacks in drilling activity in 1998, the cost of adding to a company's oil and gas reserves base has fallen, as rates charged by drilling and oil field service companies have been cut. Higher oil and gas prices and lower costs of adding reserves should, in part, offset the adverse effects of 1998's low oil prices and imbalances between capital expenditures and internally generated cash flow.

## Structural Changes in Downstream Petroleum and Natural Gas Lead to Changes in the Role and Definition of Majors

In recent years several FRS companies consolidated or exited U.S. refining and marketing. Reasons for the accompanying divestitures include low returns on investment, low refined product margins, and efforts to reduce operating costs by consolidating refining and marketing operations. The refining and marketing assets divested by incumbent FRS companies were mostly acquired by relatively small, specialized, but rapidly growing, refiners, many of which entered the FRS survey as respondents in 1998 ("entrant" FRS companies). Between 1991 (the year before the Clean Air Act Amendments of 1990 required the production of oxygenated gasolines and before California's reformulated motor gasoline requirements became effective in 1995) and 1998, the entrant FRS companies' refinery capacity increased nearly fourfold and their share of total U.S. refining capacity grew from 9 percent to 36 percent. The addition of the entrants to the FRS group increased coverage of domestic refining to 86 percent of total U.S. capacity in 1998.

The significance of natural gas transmission and electricity in FRS operations has grown considerably during the 1990's. Watershed events were Order 636 (which required the unbundling of transportation services from other sales and was promulgated in 1992 by the Federal Energy Regulatory Commission) becoming effective in 1993, and movement toward electricity deregulation both domestically and abroad. The two events enhanced the potential for a single company to market both electricity and natural gas. In 1991 only three FRS companies had significant U.S. interstate natural gas pipeline ownership (Coastal, Burlington Resources, and Occidental Petroleum). However, despite the exit of two companies from these natural gas pipeline operations, by 1998 the number had grown to five companies (Coastal, Enron, Shell Oil, Sonat, and Williams Companies), all of which also were involved in electricity (either actual operations or announced intentions). Additionally, Exxon (through its long-standing involvement in Hong Kong Power) and Texaco and Unocal (both via integration with nonconventional energy) have electricity operations.

Other changes in the composition of the FRS companies occurred during 1998. Ashland is no longer an FRS company because of reductions in its energy operations during 1997, which included selling its oil and gas producing properties and folding its downstream petroleum operations into the Marathon Ashland Petroleum joint venture operated by USX. Additionally, Oryx merged with Kerr-McGee, eliminating Oryx as an FRS respondent. Finally, although BP America and Amoco merged on December 31, 1998 (a $53-billion transaction), the two companies agreed to report separately to the FRS for 1998.

## Electric Power Emerges as a Focus of Foreign Direct Investment in Energy

As measured by outlays for acquisitions of energy assets, electric power operations just nudged out oil and gas production as the main target of foreign investors in U.S. energy in 1997. The electric power industry in the United States has historically experienced little foreign direct investment (FDI) because of Federal laws that restrict the activities of public utility holding companies (whether the owner is domestic or foreign) and prohibit the licensing of nuclear facilities that are owned, controlled, or dominated by a foreign investor. Legislative exemptions and new regulatory guidelines now allow foreign investors to avoid both of these constraints.

The largest FDI-related acquisition in the energy sector was the $1.3-billion purchase of Destec Energy, a developer and manager of electric power generation facilities worldwide, by NGC (now Dynegy), a large, diversified energy company with interests in natural gas processing and marketing and electric power production. BG in the United Kingdom and Nova Chemical in Canada each own 25 percent of Dynegy. Two other large FDI-related acquisitions were largely in natural gas production: Norway's Statoil purchased Blazer Energy (from former FRS company Ashland) and Louis Dreyfus Natural Gas (a French-affiliated, Oklahoma-based company) purchased American Exploration.

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# 1. MARKETS AND COMPANIES IN 1998

## Developments in Global Oil and Gas Markets

The major U.S. energy companies[Note 1] derive the bulk of their revenues and income from petroleum operations, including natural gas production. A majority of these companies are multinational, with 37 percent of the majors' net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the companies' financial performance. (For a list of these companies, the Financial Reporting System (FRS) companies, see the box entitled "The FRS Companies in 1998.")

During 1998, oil prices fell sharply, to levels not seen since 1973. For example, the U.S. refiner acquisition cost of imported crude oil in 1998 was $12 per barrel on an annual basis, the lowest level in 25 years.[Note 2] The decline in oil prices began in January 1997, when oil prices stood at $23 per barrel, and by December 1997, oil prices were $16 per barrel. However, it was in 1998 that oil prices fell out of the $16 to $21 per barrel trading range typical of most of the 1990's, hitting bottom in December at $9.39 per barrel.

The oil price collapse in 1998 reflected persistent imbalances between global oil supply and demand which led to unusually large buildups in petroleum inventories. The main causes of the imbalances are found in developments in 1997 and 1998, including:

- Iraq's near quadrupling of oil production through the course of 1997 and 1998
- Growth in oil production by other members of the Organization of Petroleum Exporting Countries (OPEC) and non-OPEC suppliers in 1997 (but not in 1998)
- Two successive winters with relatively mild weather
- The effects of the Asian financial crisis on demand for petroleum products (See the Highlight entitled "Asia Pacific - Economic Decline in 1998").

Oil prices began falling in 1997. In that year, worldwide crude oil production was up 3.1 percent, well above the 2.6-percent growth in world oil consumption. In 1998, with the exception of Iraq, OPEC crude oil production was flat compared with 1997 production, as was overall non-OPEC production. However, Iraq increased its production by 80 percent over their 1997 output. With a 3-percent decline in Asia-Pacific petroleum demand in 1998, there was an even greater imbalance between supplies coming to market and consumption than in 1997: worldwide oil production was up 1.4 percent in 1998 while worldwide oil consumption was essentially flat, growing only 0.1 percent.

Two years of excess oil production led to abnormally high inventories. The customary worldwide drawdowns of petroleum stocks in the first and fourth quarters simply did not occur in 1997 or in 1998.[Note 3] For example, overall petroleum stocks of the 24 industralized countries belonging to the Organization for Economic Cooperation and Development (OECD) stood at 3.8 billion barrels at the end of 1998, an all-time high. The supply-demand imbalances of the 1997 to 1998 period resulted in a drop in oil prices that nearly matched the oil price crash of 1986.

The oil price decline in 1998, which was about $6.50 per barrel on an annual basis, had devastating effects on income and cash flow from oil and gas production. However, the effects on petroleum refining financial results were mixed.

When crude oil prices decline, refiners' price-cost margins tend to benefit for a while, as refined product prices tend to lag changes in input prices. However, in 1998, the growing overhang of abnormally high petroleum inventories had the contrary effect for most of the year. The effect on refiners' margins also varied regionally, ranging from sharp declines in the Asia-Pacific region to substantial improvements in Europe. This pattern was largely a reflection of differences in petroleum demand growth, as demand was down 2.7 percent in 1998 in the Asia-Pacific region but grew 1.9 percent in the OECD Europe region. In the United States, refined product demand was up 1.6 percent between 1997 and 1998.

On the natural gas side, prices were generally down but not as steeply as oil prices. Natural gas prices are largely determined within regional (rather than global) markets, because it is relatively expensive to transport. Nevertheless, oil and gas markets are not wholly independent, and both are subject to shifting patterns of economic growth, climate, and technology. In the United States, the effects of a second consecutive mild winter tended to depress natural gas demand. Overall, natural gas consumption in the United States declined 3 percent, but U.S. production was flat and imports, mainly from Canada, returned to their recent trend, growing 5 percent between 1997 and 1998.

The result in 1998 was the third-largest build in natural gas inventories ever in the United States, with a consequent drop in prices. Natural gas prices were down 16 percent at the U.S. wellhead, equivalent to a $2 drop in the price of a barrel of oil on an energy equivalent basis.

Outside the United States, demand for natural gas grew in most regions, even the Asia-Pacific region, but at rates generally below the pace of recent years. The FRS companies reported a 6-percent decline in overall natural gas prices outside the United States, equivalent to 79 cents per barrel of oil.

The developments in oil and gas markets in 1998 had severely depressing effects on income and cash flow from oil and gas production and mixed effects on downstream petroleum (refining, marketing, and transport) financial performance. On balance, in 1998, the FRS companies' overall corporate profitability was pushed to the third-lowest level in at least 25 years.

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## Highlight: Asia Pacific - Economic Decline in 1998

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The currency devaluation, which began in mid-1997 and swept through the Asia Pacific region,[a] devastated the economies in this region in 1998. The devaluation of Thailand's currency, the baht, in mid-1997 had a spiraling effect on the surrounding countries. During the initial shock of the floating baht, Thailand's currency depreciated 50 percent. The depreciation of currencies in Indonesia, the Philippines and Malaysia were less severe, ranging between 30 and 35 percent. South Korea, Singapore and Taiwan fared better with currencies depreciating between 10 and 15 percent, while China and Hong Kong currencies fell by less than 10 percent.[b]

By the end of 1998, these nine economies (as measured by the growth in their real gross domestic product (GDP)) also experienced impacts of differing severity from the currency crisis (Table 1). Six of the nine countries had positive GDP growth in 1997, but then experienced a negative GDP growth in 1998. Indonesia's economy was most affected by the currency crisis as GDP growth registered a negative 13.5 percent compared to a 5-percent growth in 1997. The GDP for Malaysia, South Korea, and Hong

Kong dropped 7 percent, 6 percent, and 5 percent, respectively. Although the economies of Singapore and Taiwan did not experience a negative GDP growth in 1998, their GDP growth declined. For example, the GDP growth in Singapore fell from a strong 8 percent to 2 percent in 1998. Taiwan's GDP increased 5 percent, down from its growth of 7 percent in 1997. Thailand, the only country with negative GDP growth in 1997, saw its economy fall deeper into a recession in 1998: Thailand's GDP growth plummeted to a negative 9 percent from its 1997 negative 1 percent growth. However, according to preliminary data reported by the WEFA Group, an economic forecasting service, economic recovery for the affected Asian countries will occur in 1999, with the exception of Indonesia and Hong Kong in which recoveries are expected to occur in 2000.[c]

Why were the economies in some countries affected more severely by the currency crisis than others in the same region? The impact of the devaluation on each country is mainly reflective of its dependence on revenues from net exports. For example, of all the countries affected by the currency crisis, China's GDP growth was the least affected because its markets are not entirely open to world trade (Table 1). China's GDP growth was only 1 percentage point below its 1997 level. On the other hand, Indonesia, Thailand and Malaysia experienced the largest declines in GDP growth because these countries are major exporters of commodities such as rice, timber, and natural rubber.[d] In addition, the revenue bases of Indonesia and Malaysia were also negatively affected by weak world oil prices, as these countries are net oil exporters.[e] Hong Kong, another country greatly affected by the currency crisis, experienced a decline in GDP growth due to its role as a regional trade hub.[f]

What role do these Asian countries play with respect to world petroleum demand? The economic crisis in the Asia-Pacific region had a significant impact on world oil demand, as these countries are a part of the Asian Developing Countries(ADC).[g] Over the period 1992 to 1998, the ADC has had the most rapid growth in petroleum consumption in the world (Figure 1). For example, between 1992 and 1997 the annual average rate of growth in petroleum demand for the ADC was 7 percent, surpassing the average annual growth rate for the other regions by 4 percentage points or more. However, this growth was halted, and oil demand in the Asia Pacific declined 3 percent in 1998, while oil demand in the rest of the world grew 1 percent.[h] According to data in the BP Amoco *Statistical Review of World Energy*, the decline in 1998 also ended a 10-year period of oil demand growth in the Asian region. However, with the expected economic upturn in this region and the continued strength of non-Asian economies, world oil consumption is expected to increase in 1999.

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a The Asia Pacific region includes Australia, Japan, New Zealand, and the Asian Developing Countries (ADC) listed in footnote g below. In 1998, the ADC accounted for 66 percent of the oil consumption in the Asia Pacific region.

b "Developing Asia: Tigers Take Time-Out," *WEFA World Economic Outlook*: Developing Economics Pre-Meeting Forecast, Volume 1A (November 1997), p. 1.21.

c *WEFA Asian Monthly Monitor*, (August 1999), pp. HK.1 and IN.1.

d *WEFA World Economic Outlook*: Developed Economies, Volume 1A (Fourth Quarter 1998), p. 1.30.

e "East Asia: The Energy Situation", Energy Information Administration, Country Analysis Brief (August 1999), http://www.eia.doe.gov/emeu/cabs/eastasia.html.

f "East Asia: The Energy Situation", Energy Information Administration, Country Analysis Brief (August 1999), http://www.eia.doe.gov/emeu/cabs/eastasia.html.

[g] 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.

[h]BP Amoco *Statistical Review of World Energy 1999,* (June 1999), http://www.bpamoco.com/worldenergy/oil.

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## The FRS Companies' Importance in the U.S. Economy

For the reporting year 1998, 33 companies reported their financial and operating data to the Energy Information Administration's Financial Reporting System (FRS) on Form EIA-28.[Note 4] These companies (referred to as the FRS companies in this report) occupy a major position in the U.S.[Note 5] economy. In 1998, their sales were about $484 billion, or about 8 percent of the $5.7 trillion in sales of the Fortune 500 largest U.S. corporations.[Note 6] Of the top 30 companies (based on 1998 sales) on the Fortune 500 list, 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 91 percent, or $446 billion, of allocated operating revenues were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum operations (Figure 2). (For the purposes of this report, the petroleum line of business is defined to include natural gas.)

In 1998, the FRS companies accounted for 48 percent of total U.S. crude oil and natural gas liquids (NGL) production, 44 percent of U.S. natural gas production, and 85 percent of U.S. refining capacity (Figure 3). The bulk of the FRS companies' assets and new investments were devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy businesses, mainly chemicals, accounted for about 10 percent, or $47 billion, of the FRS companies' allocated revenues in 1998.

Energy production other than oil and natural gas is a relatively small part of the FRS companies' operations. During 1998 the combined operating revenues of the coal and other energy operations of the FRS companies totaled $19 billion, or only 4 percent of allocated revenues. The role of the FRS companies in the coal market is diminishing, as the companies concentrate on their core competency in oil and gas; however, coal operations still accounted for 7 percent of U.S. coal production in 1998. No FRS company has produced uranium oxide since 1991.

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# Chapter 1 Endnotes

1. The companies that reported to the FRS for the years 1974 through 1998 are listed in Appendix A, Table A1. Four of the FRS companies are owned by foreign companies: Amoco and BP America--both now owned by BP Amoco; Fina--owned by TotalFina; and Shell Oil--owned by Royal Dutch/Shell.

2. In this chapter, international energy data were obtained from BP Amoco, *Statistical Review of World Energy* (London, June 1999); annual and monthly U.S. energy industry price and quantity data are from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999); GDP data are from the WEFA Group, *World Economic Outlook* (August 1999).

3. Jay Hakes, *Statement Before the Energy and Natural Resources Committee, U.S. Senate* (January 28, 1999), available at http://www.eia.doe.gov/neic/speeches/senate/senate.html (see figures 3 and 4).

4. Aggregate time series data from Form EIA-28 for 1977 through 1998 and previous editions of this report can be obtained from the EIA (see http://www.eia.doe.gov/emeu/perfpro/wk1/frsdata.html).

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 (see http://www.pathfinder.com/fortune.

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# The FRS Companies in 1998

(* denotes new survey entrant in 1998)

Amerada Hess Corporation
Amoco Corporation
Anadarko Petroleum Corporation
Atlantic Richfield Company (ARCO)
BP America, Inc.
Burlington Resources, Inc.
Chevron Corporation
*CITGO Petroleum Corporation
*Clark Refining and Marketing, Inc.
Coastal Corporation
Conoco, Inc.
Enron Corporation
*Equilon Enterprises, L.L.C.
Exxon Corporation
Fina, Inc.
Kerr-McGee Corporation
*Lyondell-CITGO Refining, L.P.
Mobil Corporation
*Motiva Enterprises, L.L.C.
Occidental Petroleum Corporation
Phillips Petroleum Company
Shell Oil Company
Sonat, Inc.
*Sunoco, Inc.
*Tesoro Petroleum Corporation
Texaco, Inc.
*Tosco Corporation
*Ultramar Diamond Shamrock Corporation
Union Pacific Resources Group
Unocal Corporation
USX Corporation
*Valero Energy Corporation
*Williams Companies, Inc.

**Table 1. Real GDP Growth Rates for a Select Group of Asian Countries, 1996-1999**
(percent change)

| **Countries**[a] | **1996** | **1997** | **1998** | **1999** |
|---|---|---|---|---|
| China | 9.7 | 8.8 | 7.8 | 7.1 |
| Hong Kong | 5.6 | 5.3 | -5.1 | -1.0 |
| Indonesia | 8.0 | 4.6 | -13.5 | -1.7 |
| Japan | 4.1 | 0.8 | -2.9 | 1.3 |
| Malaysia | 8.6 | 7.8 | -6.7 | 3.8 |
| Philippines | 5.7 | 5.2 | -0.5 | 3.2 |
| Singapore | 6.9 | 7.8 | 1.5 | 4.7 |
| South Korea | 7.1 | 5.5 | -5.8 | 7.5 |
| Taiwan | 5.7 | 6.8 | 4.8 | 5.5 |
| Thailand | 5.5 | -0.5 | -9.4 | 3.8 |

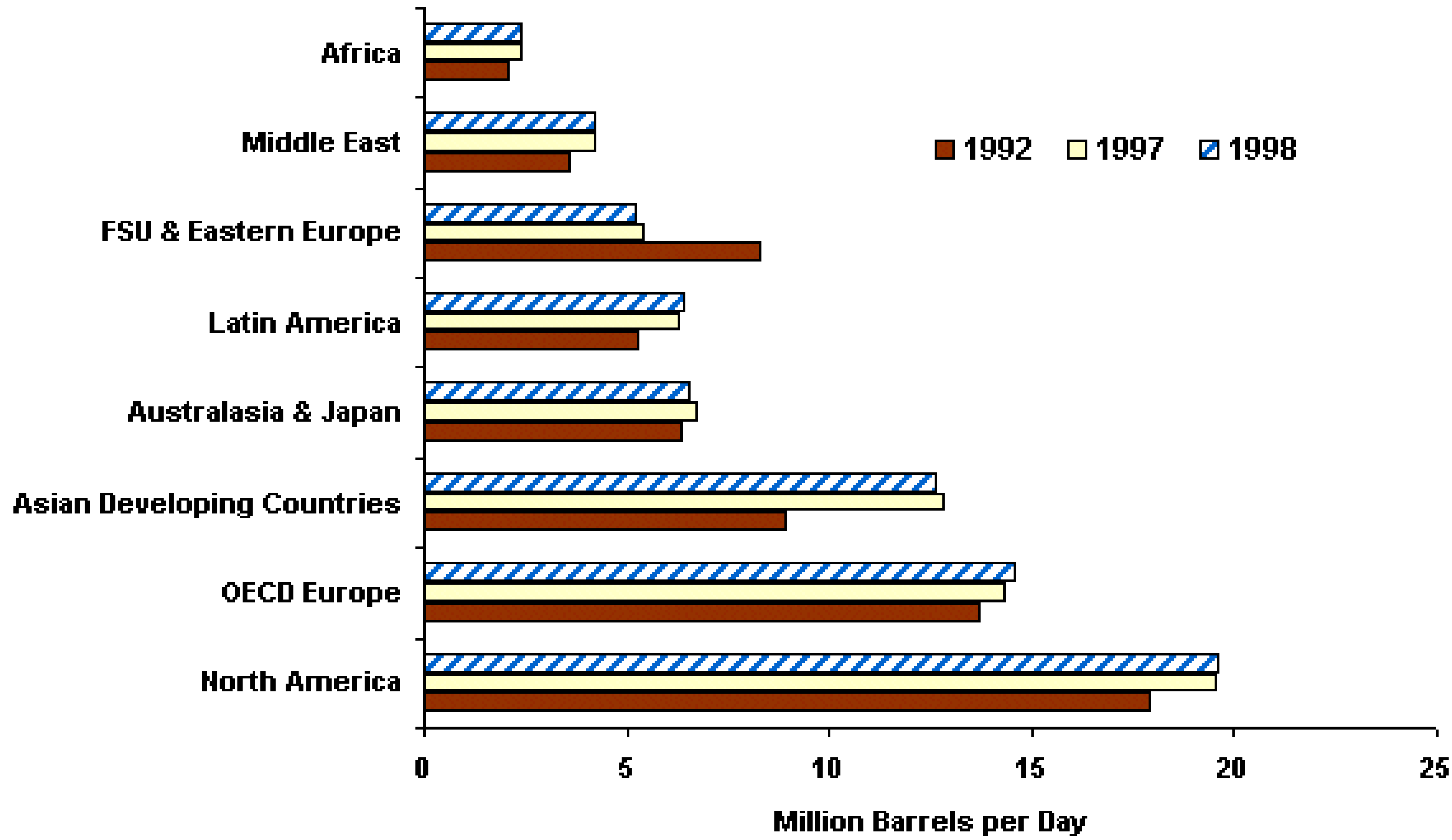
[a]All the countries, with the exception of Japan, were negatively impacted by the currency crisis resulting from the floating Thailand currency, the baht, in mid-1997.

Note: 1999 real GDP growth is estimated.

Sources: **1999-1998**: Asia Economic Outlook, Fourth Quarter 1999 (October 1999), pp. SM.1 and SM.2; and **1997-1996**: WEFA Group: *Asian Monthly Monitor* (December 1998).

*Last Updated on 12/9/99*

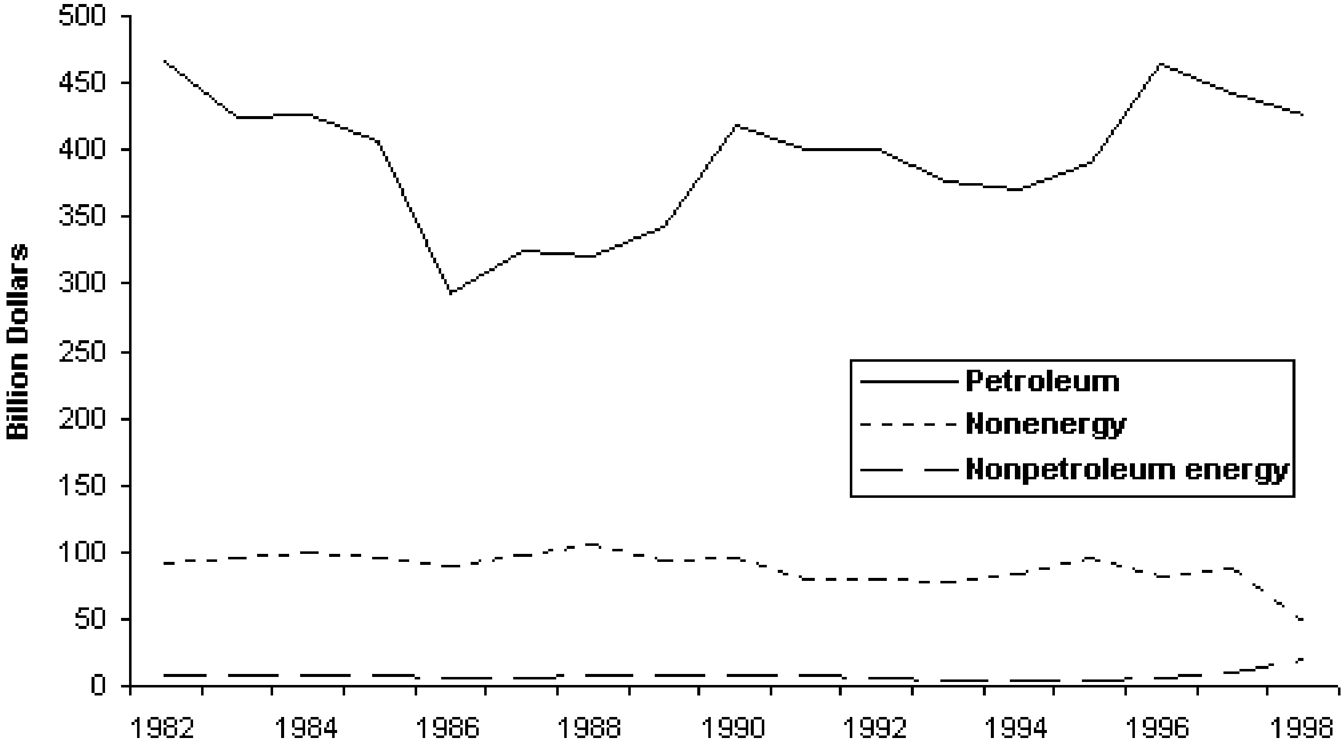
**Figure 1. Petroleum Consumption by Region, 1992, 1997, and 1998**




Note: FSU = Former Soviet Union.

Source: BP Amoco, *Statistical Review of World Energy* June 1999, p. 10.

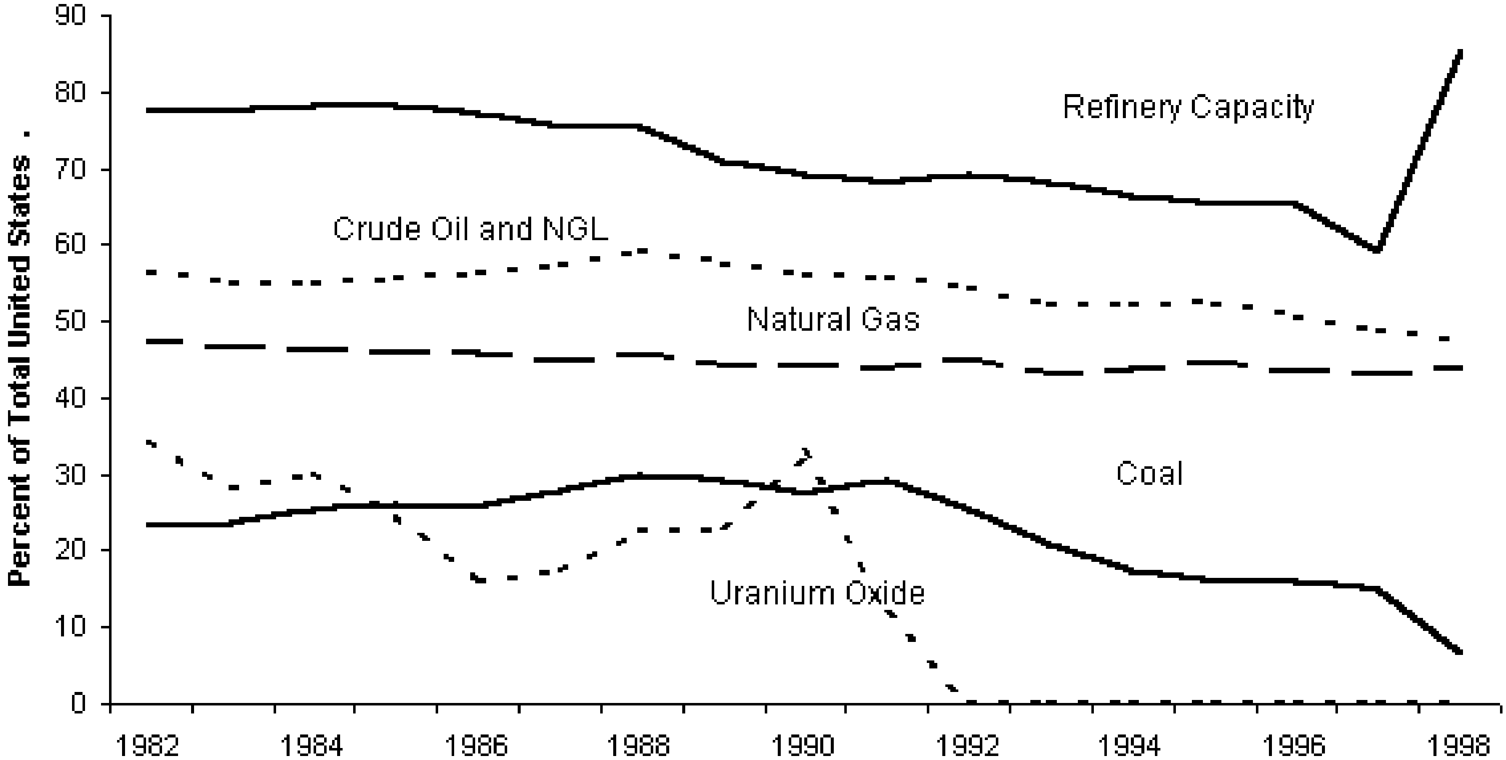
**Figure 2. Operating Revenues by Line of Business for FRS Companies, 1982-1998**




Note: Petroleum includes natural gas.

Source: Financial Analysis Team, Office of Energy Markets and End Use, Energy Information Administration, Form EIA-28 (Financial Reporting System).

**Figure 3. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1982-1998**




Sources: Table B1; Total industry uranium oxide production is from Energy Information Administration, *Uranium Industry Annual 1992,* DOE/EIA-0478(92) (Washington, DC, October 1993).

# 2. FINANCIAL DEVELOPMENTS IN 1998

In 1998, oil prices had their greatest collapse since the oil price crash of 1986. The collapse in oil prices, together with lower natural gas prices, had devastating effects on the financial performance of the FRS companies. Net income fell 61 percent in 1998, from 1997's all-time record level, to $12.5 billion. The profitability of the FRS companies, which had been generally keeping pace with other large U.S. industrial corporations in the 1990's,[Note 7] tumbled to its third-lowest point in the last 25 years (Figure 4).

This chapter reviews key aspects of the financial performance of the FRS companies. Major topics include sources of income and cash flow, targets of investment, and deployment of capital. The review for 1998 is complicated somewhat by the addition of 11 respondents to the FRS reporting group.[Note 8] Therefore, whenever the contribution of the new respondents has a material effect on the item under review, the information will be reported with and without the new respondents. For example, excluding the new respondents shows that total sales revenues for companies reporting to the FRS in 1997 and 1998 declined 24 percent, rather than only 8 percent for all companies (Table 2). Generally, U.S. petroleum refining and marketing information is strongly affected by the new respondents, while other lines of business are rarely affected materially.

## Income and Cash Flow

### Upstream Profitability Hits Post-Embargo Lows

Oil market developments in 1998, which were largely continuations of adversities that began in 1997, had a devastating effect on the FRS companies' upstream income and profitability. In 1998, the profitability of the FRS companies' investments in oil and gas production, both in the United States and abroad, hit its lowest point in at least 22 years (Figure 5). The plunge in profitability was in contrast to upstream performance in 1996 and 1997, when rates of return reached their highest levels since the period of elevated oil prices in the early 1980's. Net income from oil and gas production in 1998, excluding unusual items,[Note 9] was down 74 percent in the United States from the prior year and down 50 percent abroad (Table 3).[Note 10]

The severe deterioration in upstream financial performance can be almost wholly attributed to lower prices, particularly oil prices. The world oil price (as represented by the U.S. refiner acquisition cost of imported crude oil) steadily declined--from $23.02 per barrel in January 1997 to a nadir of $9.39 in December 1998, a level not seen since 1973. On an annual basis, 1998 oil prices were more than $6 per barrel lower than in 1997. Natural gas prices at the U.S. wellhead fell a less steep 16 percent over the same period, or by about $2 per barrel of oil equivalent.

The FRS companies' 5 percent cut in U.S. oil production additionally hurt their financial results (their U.S. natural gas production was up 1 percent). Abroad, the FRS companies increased oil and gas production by 5 percent and 7 percent, respectively, which somewhat moderated the effects of lower prices.

Although upstream cost cutting by the FRS companies continued in 1998, these efforts were overwhelmed by price declines in 1998. (For additional discussion of upstream financial results, see the section entitled, "Oil and Gas Production" in Chapter 3.)

### Refiners Show Improved U.S. Performance Despite Price-Cost Squeeze

Net income from the FRS companies' U.S. refining marketing operations, excluding unusual items, more than doubled between 1997 and 1998 (Table 3). This was the third consecutive increase in annual earnings from these operations. Even excluding the $2.0 billion contributed to U.S. refining/marketing net income by the new FRS respondents, the incumbent FRS companies still registered a 50-percent gain in net income. This gain is remarkable in that the margin between refined product prices and crude oil input prices shrank in 1998 and incumbent FRS companies sold three refineries during the year. How did the FRS companies accomplish this bottom-line improvement?

For the incumbent companies, the spread between refined product prices and the cost of raw material inputs (the "gross margin") declined by 43 cents per barrel, even through crude oil prices declined sharply in 1998. The margin squeeze reflected the downward pressures on refined product prices exerted by unusually high petroleum inventories and a second consecutive mild winter. However, incumbent FRS refiners were able to cut their U.S. refining/marketing operating costs by 47 cents per barrel, which was more than enough to offset the decline in the gross margin. Also, revenues from other activities (such as convenience stores and shipping services performed for other companies) held up despite the sale of three refineries.

The profitability of U.S. refining/marketing operations, as measured by return on investment,[Note 11] also rose for the third consecutive year, reaching a 9-year high in 1998 (Table 4). The increase in profitability suggests that strategies such as cost-cutting and expansion of the scope of petroleum marketing activities continued to improve performance in 1998 despite a squeeze on margins.

### Stability in Foreign Downstream Earnings Obscures Market Turmoil

Net income from foreign refining/marketing in 1998 was down 7 percent from the prior-year level, to $3.7 billion (Table 3). However, this modest decline belies marked differences in regional financial results.

The effects of the Asian financial crisis, which was set off by a series of currency devaluations beginning in mid-1997, continued through 1998. Six countries (Indonesia, Japan, Malaysia, the Philippines, South Korea, and Thailand) and Hong Kong were in recession in 1998, registering decreases in real Gross Domestic Product ranging from negative 0.5 percent (Philippines) to negative 13.5 percent (Indonesia).[Note 12] Recession led to reduced demand for petroleum products in the Asia-Pacific region and a buildup of excess crude oil inventories. Figure 6 shows that Asian-Pacific price-cost margins (as represented by the Singapore/Dubai refining margin) were down sharply in 1998 following a sharp decline in 1997. The FRS companies with significant Asia-Pacific downstream operations--Chevron, Exxon, Mobil, and Texaco--noted in their annual reports that refining margins declined in the region and, further, that adverse currency movements had negative effects on earnings. These developments were reflected in earnings from unconsolidated affiliates. The majority of the FRS companies' unconsolidated affiliates' refinery capacity is located in the Asia-Pacific region. Income from unconsolidated affiliates in foreign refining/marketing was down 88 percent in 1998, to a new low in the 1990's (Figure 7).

In contrast, margins in Europe (represented by the Rotterdam/Brent refining margin) were higher in 1998 (Figure 6) as economic growth in most European countries improved, as did the demand for petroleum products. A majority of the FRS companies' foreign refinery capacity that is consolidated for financial reporting purposes is located in Europe. Accordingly, net income from consolidated foreign refining/marketing operations was up 20 percent, reaching a level in the 1990's nearly matching that of 1991 when the Persian Gulf conflict caused a surge in petroleum prices and refining margins (Figure 7).

### Cyclical Downswing and Conoco Spinoff Depress Chemical Earnings

The nonenergy line of business has generally been the second most important source of income for the FRS companies after the petroleum line of business. The nonenergy line of business consists primarily of chemical operations and also a variety of diversified businesses outside energy. The role of nonenergy businesses as a source of income tends to vary directly with cyclical patterns in the chemical industry. For example, the nonenergy line of business accounted for 35 percent of total FRS company line-of-business net income in 1988 when the profitability of chemical operations was at an all-time peak. This share fell to 8 percent when chemical profitability hit a trough in the 1991 to 1992 period and rose to 45 percent in 1995, the most recent year of peak chemical profitability. The chemical industry has been in a downswing since 1995(Figure 8), as worldwide production capacity increased faster than the demand for chemicals. Financial results for 1998 were also affected by the Asian financial crisis and the accompanying drop in demand for industrial products generally and chemicals in particular.

As a result, profitability of chemical operations continued to decline in 1998 and the nonenergy line of business accounted for only 9 percent of total line-of-business net income, excluding unusual items (Table 3). The 61-percent decline in income from chemical operations (Table 5) [Note 13] overstates the severity of the decline, though, because of the changes in the makeup of the FRS survey group. Beginning with the 1998 reporting year, DuPont's chemical and related businesses were no longer included in the FRS database, Ashland Oil exited from the FRS survey group, and ARCO sold its chemical operations. Two added respondents, Sunoco and Ultramar Diamond Shamrock, reported financial information for chemical businesses. Excluding these companies, operating income from the remaining FRS companies' chemical operations declined 33 percent between 1997 and 1998. This decline was widespread and nearly all of the FRS companies noted that price-cost margins in their chemical operations narrowed in 1998 despite lower feedstock costs stemming from lower oil and gas prices. For example, Chevron stated that, in its chemical operations in 1998, "Earnings continued to decline in response to industry over-capacity and lower demand resulting from the Asian economic crisis."[Note 14]

Other businesses outside energy performed poorly in 1998, despite the continued strong growth of the U.S. economy. Even after adjusting for survey group changes and unusual items, this line of business had an operating loss of $352 million in 1998 compared to operating income of $540 million in 1997 (Table 5). Nonfuel minerals operations contributed to diminished income in 1998. In an analysis of U.S. Steel Group's $288-million decline in operating income in 1998, USX said, "... income for U.S. steel operations decreased primarily due to lower average steel product prices, lower shipment volumes, and less efficient operating levels, resulting from an increase in imports and weak tubular markets."[Note 15] Unocal's "Carbon & Minerals" business registered a loss of $28 million in 1998 compared to operating income of $109 in 1997. Unocal noted that a plant shutdown at a California mining facility was the principal cause of the loss.[Note 16] Exxon observed that a $50-million drop in earnings from other operating segments reflected significantly lower copper prices. Also, in response to a request from EIA, Exxon reclassified its Hong Kong Power subsidiary from the other nonenergy line of business[Note 17] to the other energy line of business. This change contributed about $300 million to the decline in income from the other nonenergy line of business.

Enron provided a rare positive note to other nonenergy financial results. In discussing their recently formed communications business, Enron said, "...results in 1998 were favorably impacted by increased earnings related to ECI (Enron Communications, Inc.) from the sale of capacity on its fiber-optic network."[Note 18] This earnings improvement was partially offset by another FRS company's results from its communications business. Williams Companies, which became an FRS respondent for the 1998 reporting year, disclosed an operating loss of $175 million for its communications business.[Note 19]

## Electricity Investments Brighten the Bottom Line in 1998

### *Other Energy*

So far in the 1990's, income from other energy has grown at the most rapid rate among all of the FRS companies' lines of business. Net income from the other energy line of business more than doubled between 1990 and 1997, and in 1998, at $0.9 billion, was about triple that of 1997 (Table 3). Prior to 1990, this line of business yielded 16 consecutive years of operating losses. Similarly, the profitability of the FRS companies' other energy line of business has steadily risen in the 1990's (Table 4).

Despite the ever-improving performance of other energy businesses, only a small minority of FRS companies have significant asset commitments in this area. The main focus of investments in other energy is electricity generation and cogeneration, with geothermal resources and synthetic oil and gas production largely accounting for the balance.

Both the level and growth of net income in other energy in 1998 were largely traceable to electricity generation and cogeneration businesses. For example, Coastal Corporation, which owns and operates electricity production facilities in the United States, Latin America, and China, reported a 58-percent increase in income from its "Power" business.[Note 20] Enron is involved in the electric power business on a global scale. The company reported more than a doubling in the amount of electricity it marketed at wholesale, between 1997 and 1998. This growth in part reflected its merger with Portland General Electric, which became effective in July 1997. The contribution of a full year's activity by Portland General Electric in 1998 added nearly $200 million to income.[Note 21] Unocal has long been involved in the development and sale of geothermal resources, and, more recently, in the construction and operation of electrical generation plants abroad. Further, despite the severe recession in Indonesia, Unocal reported a doubling in income from its "Geothermal & Power Operations" business, principally as the result of increased generation and sales of electricity in Indonesia from plants that recently came on line.[Note 22]

Texaco, like Unocal, has combined electricity assets with nonconventional energy production into a single business. Texaco owns and operates electricity cogeneration and generation projects. The company also develops and markets proprietary technologies that convert hydrocarbons (such as coal and petroleum coke) into synthetic gas that can be used for power generation or as chemical feedstock. In 1998, Texaco's financial results improved in this business in that after-tax losses were $25 million less than in 1997.[Note 23]

Exxon has been extracting oil from Canadian tar sands since the 1970's, and no doubt the markedly lower oil prices of 1998 adversely affected financial performance in these operations. Exxon has owned a large stake in its Hong Kong Electric subsidiary since the early 1980's. However, until 1998, the financial results from Hong Kong Electric were included in the other nonenergy line of business. Beginning with the 1998 reporting year, this business is included in other energy (per a request by EIA). However, income added by this reclassification did not alter the observation that the other energy line of business did very well in 1998: excluding Exxon, income still more than doubled between 1997 and 1998.

### *Coal*

Income from the FRS companies' coal operations in 1998, excluding unusual items, fell a steep 41 percent between 1997 and 1998. However, comparison of income reported in 1998 for the coal line of business with income in 1997 is complicated by ownership changes and changes in the FRS respondent group. The following changes affected the coal line of business in 1998:

- Kerr-McGee and ARCO completed their exit from U.S. coal operations.
- DuPont's coal-producing subsidiary, Consol Coal, was not spun off with Conoco. Only Conoco is included in the FRS survey beginning in 1998.
- Ashland Oil and its Arch Coal subsidiary were dropped from the FRS group and Sunoco and its Sun Coke business were added.

Excluding the above companies and focusing on the six FRS companies that reported coal production in 1997 and 1998 reveals that financial results for their coal operations posted a notable improvement--net income from coal, excluding unusual items, was up 36 percent. The six FRS coal producers increased their U.S. output by 5 percent, which led to a $29-million increase in revenues, despite generally lower coal prices in 1998. Meanwhile, these companies shaved their coal-related operating costs by $42 million. These results are better than those posted by a group of 11 specialized U.S. coal-producing companies.[Note 24] For this latter group of companies, income, excluding unusual items, was down 1 percent between 1997 and 1998 as cost cutting did not quite keep pace with revenue declines.

### *Pipelines*

Net income, excluding unusual items, from the FRS companies' pipeline systems was nearly unchanged at $2.0 billion. The apparent stability in financial results for pipelines masks several changes in the composition of pipeline ownership among the FRS companies in 1998. The changes include:

- Shell Oil and Texaco contributed their liquids pipelines to their Equilon and Motiva downstream joint ventures.
- Ashland, which was dropped from the FRS group, contributed its pipeline systems to Marathon Ashland Petroleum, its downstream joint venture with USX, which began operating in 1998.
- Three companies which were added to the FRS group beginning with the 1998 reporting year each own liquids pipelines systems.
- Shell Oil's acquisition of Tejas Gas made it a significant owner of natural gas pipeline assets.
- Occidental Petroleum left the natural gas pipeline business when it completed the sale of its MidCon subsidiary to KN Energy in 1998.

Financial results for FRS companies that reported pipeline activity in both 1997 and 1998 indicate that 1998 was not an especially good year to be invested in pipelines. Alaska oil production continued to decline in 1998, falling over 9 percent from production in 1997. The three FRS companies that own most of the Trans Alaskan Pipeline System (TAPS) collectively reported a 5-percent drop in net income, as cost reductions did not match revenue losses stemming from the reduction in Alaska crude oil throughput. Other FRS companies with lower-48 liquids pipelines operations registered an 18-percent decline in net income. This latter group's 4-percent gain in pipeline revenues was wiped out by increased operating costs in 1998.

Natural gas pipelines appeared to take a financial hit in 1998 as natural gas consumption fell 3 percent and natural gas inventories reached a year-end record, largely due to a relatively mild winter. For a consistent group of FRS natural gas pipeline owners, net income in 1998 from these operations was down 5 percent from prior-year income.

### Cash Flow at Lowest Level Since the Oil Price Crash of 1986

Excluding companies that joined the FRS ranks in 1998, the FRS companies' cash flow from operations in 1998, at $44.4 billion, was at the lowest level since 1986, the year of the previous oil price crash.[Note 25] This sharp decline in cash generated within the companies' operations follows an all-time high for cash flow in 1997. Lower oil and gas prices were largely responsible for this deterioration in cash flow. The $23-billion decline in pretax cash flow from worldwide oil and gas production (Table 6) largely reflected a $26-billion drop in oil and gas revenues in 1998 (see Chapter 3 for a detailed discussion of financial results in oil and gas production). Nonenergy businesses also generated much less cash in 1998 than in 1997: $7.0 billion less. Even excluding DuPont, whose chemical operations were absent from FRS results in 1998, cash flow from these operations was down $3.4 billion, reflecting the deterioration in market conditions in the FRS companies' businesses outside energy.

Nearly all of the financial impact of the 11 new respondents in 1998 was in downstream petroleum (refining, marketing, and transport) results. This group accounted for $4.5 billion of pretax cash flow from downstream petroleum, virtually all from U.S. operations. Apart from this group, the FRS companies' cash flow from worldwide downstream operations was flat from 1997 to 1998.

## Targets of Investment

### Capital Expenditures Near Record-Level Despite Plunge in Cash Flow

Capital expenditures of the FRS companies[Note 26] totaled $75.1 billion in 1998 (Table 7), a level exceeded only in 1984 when three then mega-mergers were consummated among the FRS companies (Chevron-Gulf Oil, Texaco-Getty Oil, and Mobil-Superior Oil) (Figure 9).[Note 27] Companies reporting to the FRS for the first time in 1998 accounted for $6.1 billion of the overall $13.2-billion increase over 1997 capital expenditures. Even excluding the new reporters, incumbent companies' capital expenditures were the third highest on record, slightly below 1982's expenditures when three other mega-mergers involved FRS companies (DuPont-Conoco, Occidental Petroleum-Cities Service, and USX-Marathon Oil).

Several developments lay behind the surge in capital expenditures:

- Mergers and acquisitions accounted for $20.7 billion in capital expenditures in 1998, up from $13.2 billion in 1997.
- Expenditures for oil and gas exploration were up in all but one region.
- The FRS companies increased outlays for development of oil and gas fields in the relatively mature producing areas of the North Sea, South America, and onshore locales in the United States,

including Alaska.

- The FRS companies with ongoing U.S. downstream operations increased their outlays for refinery upgrades and gasoline marketing facilities.

### *Mergers and Acquisitions*

The primary focus of the FRS companies' spending on mergers and acquisitions in 1998 was oil and gas production. Seven companies (ARCO, Coastal, Kerr-McGee, Occidental Petroleum, Sonat, Union Pacific Resources, and USX) were especially active in acquiring already proven reserves of oil and gas. Each of these companies increased its worldwide oil and gas reserve base by at least 15 percent through acquisitions in 1998.

In the United States, capital expenditures related to upstream mergers and acquisitions totaled $6.7 billion.[Note 28] The largest U.S. transaction was Occidental Petroleum's $3.5-billion acquisition of the U.S. government's 78-percent interest in the Elk Hills Naval Petroleum Reserve in California (Table 8). The company, which is headquartered in California, plans to use improved drilling and field management techniques to fully develop the property.[Note 29] Sonat, which is primarily a natural gas pipeline company with significant involvement in natural gas and electricity marketing, greatly extended its upstream asset commitment in 1998 through the acquisition of Zilkha Energy, in a transaction valued at $1.3 billion. This transaction brought Sonat into the ranks of offshore producers, as most of the acquired properties are located in the Gulf of Mexico.

Outside the United States, the FRS companies' capital expenditures for mergers and acquisitions were $8.0 billion in 1998. Two billion-dollar-plus acquisitions largely involved Canadian oil and gas reserves. In the largest of these transactions, at $2.6 billion, Union Pacific Resources acquired Canadian-based Norcen Energy Resources, an international oil and gas producer with 60 percent of its reserves located in Western Canada. According to Union Pacific Resources' president, "This acquisition gives UPR new core areas in Canada and Latin America plus a significant strategic expansion in the Gulf of Mexico including the deep water."[Note 30] In a transaction valued at $1.2 billion, USX acquired Tarragon Oil and Gas, a Canadian oil and gas producer, which added 20 percent to USX's worldwide reserves of oil and gas.[Note 31]

The largest transaction abroad was ARCO's acquisition of Union Texas Petroleum Holdings, with a value of $3.3 billion. ARCO acquired properties mainly in Indonesia, the North Sea, and Venezuela. The acquisition was a good fit for ARCO in that 90 percent of the acquired properties are in ARCO's core foreign oil and gas producing areas.[Note 32]

Outside oil and gas production, the largest acquisition among the FRS companies was Shell Oil's acquisition of Tejas Gas for $2.8 billion. This transaction largely accounted for the tripling, between 1997 and 1998, in FRS companies' overall capital expenditures for pipelines (Table 7). Tejas Gas (subsequently renamed Tejas Energy) is primarily an intrastate natural gas pipeline company, with 12,500 miles of pipeline in Texas, Oklahoma, and Louisiana, as well as midstream natural gas businesses such as natural gas liquids transport and marketing. This acquisition, together with Shell's acquisition of Coral Energy, positions the company to expand further into energy services. According to Shell, "The name Tejas Energy symbolizes our transformation from a large intrastate natural gas pipeline company to the engine for Shell's growth in the midstream natural gas and power business," and "The next step for Tejas Energy is to develop a strategy for entering the deregulated power generation market."[Note 33]

Power generation and services were targets of Enron's acquisition strategy in 1998 as well. Enron continued to move into electric power abroad as it has been doing for several years through two acquisitions, one in the United Kingdom and one in Brazil, totaling nearly a billion dollars. Also in the United Kingdom, Enron diversified into the water supply and distribution business through its acquisition of Wessex Water. This $0.9-billion acquisition, together with new FRS respondent Williams Companies' capital expenditures for its telecommunications business of $0.4 billion, accounted for nearly all of the 147-percent increase in the FRS companies' overall capital expenditures for the other nonenergy line of business.

New FRS respondents accounted for all of the acquisitions of U.S. refining/marketing assets shown in Table 8. Incumbent FRS companies owned three of the four refineries that changed hands. (For a detailed discussion of the downstream characteristics of the new FRS respondents, see the Special Topic entitled "The Changing Profile of the U.S. Majors -- Is Smaller Better?" in Chapter 4.)

### *Exploration and Development*

Despite the severe drop in oil prices and lower natural gas prices, the FRS companies increased their worldwide exploration expenditures (excluding expenditures for unproved acreage) by $0.8 billion in 1998. The increase in outlays for discovering additional deposits of oil and gas extended to all regions except the North Sea (shown within the OECD Europe region in Figure 10). The Gulf of Mexico registered the largest increase in exploration expenditures. The attraction of large field projects and applications of advancing technologies was not wholly offset by lower oil and gas prices in 1998, as 13 of 22 companies reporting offshore expenditures increased outlays for exploration in the Gulf of Mexico. Companies reporting increased exploration expenditures included companies heavily involved in deepwater projects as well as more conventional offshore drilling.

Deepwater projects are a large part of the story behind the surge in exploration expenditures in Africa. Deepwater drilling in Angola, on the west coast of Africa, has been particularly attractive. Since 1995, this area has yielded 18 major finds, with nearly 8 billion barrels in oil and gas reserves, only one of which was abandoned. Chevron and Exxon have discovered 10 fields in deepwater off Angola, with nearly 4 billion barrels in total reserves.[Note 34] Several FRS companies are involved in searching for oil and gas in North Africa, including Amoco (Egypt), Anadarko (Algeria), ARCO (Algeria), and USX (Egypt). This latter group of companies registered a 30-percent overall increase in exploration spending in Africa.

The Mideast registered the steepest increase in exploration spending, at 150 percent, among the regions in 1998. Although most of the Mideast remains off limits to direct ownership by foreign companies, a number of countries have production-sharing agreements with FRS companies, including Abu Dhabi, Bahrain, Oman, Qatar, and Yemen. The agreements generally include exploratory activity. For example, Chevron signed production-sharing agreements with Bahrain and Qatar and began seismic work and exploratory drilling during 1998, while Phillips Petroleum acquired seismic data in conjunction with its recent production-sharing agreement with Oman.[Note 35]

Development expenditures are directed toward drilling and equipping wells to extract oil and gas and increasing the recovery of oil and gas from proven reserves. The North Sea was the main target of increased development spending in 1998. Although the North Sea is viewed as a generally mature producing area, capable of yielding added production through improved recovery techniques, the number of development wells drilled by the FRS companies in this area increased by 45 percent between 1997 and 1998 to an all-time high of 137 wells.

Nearly all of the 13 FRS companies producing oil and gas in Europe reported an increase in development spending or drilling. The commentary in annual reports generally indicated that companies continued to push ahead with scheduled projects. For example, Texaco reported the biggest increase in development well completions, from 9 to 23, through which the company was able to increase its North Sea oil and gas production by 38 percent between 1997 and 1998.[Note 36] Exxon, which drilled the most development wells in Europe (42 in 1998, up from 33 wells in 1997), noted that three North Sea development projects started producing in 1998.[Note 37] Amerada Hess, which increased development expenditures in Europe by nearly $250 million, reported that production began from three new developments in the United Kingdom section of the North Sea, while in the Danish North Sea, the South Arne Field was in the final stages of development.[Note 38] (For more information on North Sea drilling, see the Special Topic entitled "The North Sea -- Development Outpaces Exploration" in Chapter 4.)

Onshore locales in the United States registered an overall increase of $200 million in capital expenditures directed toward development of production in proven fields (Figure 11). The increase in expenditures was largely clustered among companies involved in Alaska North Slope oil production and South Texas natural gas production.

In Alaska, ARCO reported a doubling of expenditures for Alaska. ARCO's main target is the development of the Alpine oil field, which is expected to produce 70 thousand barrels per day by 2001.[Note 39] ARCO also noted that adaptations of 3-D graphics technology used in the aeronautics and automobile industries are expected to improve safety and reduce operating costs when the Alpine Field is brought online in mid-2000. Both ARCO and Exxon[Note 40] reported that they began development activity in 1998 aimed at smaller fields adjacent to Alaska's mature Prudhoe Bay field.

In South Texas, Conoco significantly increased drilling activity in Lobo Trend properties purchased in 1997 for nearly $1 billion. By the end of 1998, Conoco increased its natural gas production from this area by 47 percent.[Note 41] Also in South Texas, Coastal reported increases in natural gas production through development of the Vicksburg Trend, producing from deposits as deep as 15,000 feet.[Note 42]

Despite these successes, a majority of the FRS companies responded to the drop in oil and gas prices by cutting back on U.S. onshore development expenditures between 1997 and 1998. The cutbacks ranged from near zero to 60 percent, averaging 17 percent. The number of wells initiated in a year is a more price-sensitive indicator of the response to market developments than is expenditures.[Note 43] This indicator does not bode well for near-term U.S. onshore oil and gas development, as the number of exploratory wells initiated by the FRS companies at U.S. onshore locales was down a stunning 36 percent between 1997 and 1998.

Comparing Figure 10 and Figure 11 shows a negative correlation across regions between the change in exploration expenditures and the change in development expenditures. That is, areas with more frontier prospects, such as Africa and the U.S. offshore, which were targets of increased exploration spending in 1998, tended to be less favored as targets of development, while the opposite tended to prevail for the more mature areas. The exception to this pattern was the Other Western Hemisphere region, which ranked high in both categories of expenditures.

In fact, taking exploration and development expenditures (excluding expenditures for acreage) together, the Other Western Hemisphere registered the largest increase of all regions. The increase in expenditures was concentrated among the six companies that recently commenced a variety of joint ventures with Petroleos de Venezuela, the state energy company of Venezuela (ARCO, Chevron, Conoco, Mobil, Phillips Petroleum, and Texaco). The projects, all located in Venezuela, include rejuvenating production from existing fields, production and processing of unusually heavy crude oils, and exploration and development of new fields both onshore and offshore. (For a more detailed discussion, see the Special Topic entitled "Venezuela Offers Full Market Value to Encourage Foreign Investment in Oil" in the 1997 PDF edition of this report.)

### *Refining and Marketing*

Among all of the lines of business, interpretation of capital expenditures data for U.S. refining and marketing is the most muddled by restructuring and changes in the FRS respondent group. When the effects of these latter developments are purged, however, it is clear that U.S. refining was a target of investment among those incumbent FRS companies with ongoing downstream operations. It can be shown that this group increased capital expenditures for their U.S. refining and marketing operations by 20 percent between 1997 and 1998.

To obtain this result, begin by noting that the new FRS respondents (each of which was selected for its importance in U.S. refining) accounted for $3.9 billion in added capital expenditures for U.S. refining/marketing in 1998. One billion dollars of that amount was for acquisitions of mostly former FRS refineries. Next, note that Shell Oil and Texaco contributed their refining/marketing assets to the Equilon and Motiva joint ventures in 1998 and no longer directly make capital expenditures for U.S. refining/marketing. Ashland Oil was dropped from the FRS group beginning with the 1998 reporting year because of its reduced involvement in energy. Lastly, when Union Pacific Resources (UPR) established its natural gas gathering, processing, trading, and marketing operations as a separate business in 1997, it reclassified nearly $400 million in U.S. oil and gas production property, plant, and equipment to a capital expenditure in downstream transport.

The remaining 12 FRS incumbents that have U.S. refining and marketing facilities which they directly operate increased their capital expenditures for their U.S. refineries by 23 percent, their gasoline marketing networks by 10 percent, and their storage and distribution facilities by 65 percent, between 1997 and 1998. Based on comments by the companies, investments tended to focus on refinery upgrades, modest expansions of gasoline marketing networks, and/or installation of specialized downstream units, but little in the way of dramatic initiatives was evident in 1998. USX's comment was representative, "Downstream spending ... consisted of upgrades and expansion of retail marketing outlets and refinery modifications."[Note 44] Exxon noted, "A phased start-up of a $200-million, 150-megawatt cogeneration facility began at the Baton Rouge, Louisiana complex. When fully commissioned in 1999, the project will provide steam, eliminate external power purchases, and sell excess electricity. To reduce raw material costs, facilities came on line at Baytown and Baton Rouge [refineries] to process more heavy high-sulfur crude."[Note 45] While Coastal observed, "... improved performance results from operational enhancements and investments to produce lighter, higher value products from lower cost heavy and sour crudes."[Note 46]

The overall 20-percent increase in capital expenditures for U.S. refining and marketing in 1998 by the incumbent refiners follows a 14-percent increase in expenditures in 1997. This upswing in expenditures reflected the recent improvement in the profitability of U.S. refining and marketing. For the incumbent refiners, return on investment in these operations rose steadily from near zero in 1995 to 11 percent in 1998. In contrast, other FRS companies' return on investment in U.S. refining/marketing increased from 2 percent to only 5 percent over the same period.

### *Other Lines of Business*

Chemicals evidenced the largest decline, $3.9 billion, in capital expenditures among the lines of business. However, this apparent decline was entirely due to the absence of DuPont and their massive chemical operations from the FRS reporting group beginning with the 1998 reporting year. Excluding DuPont, the FRS companies' capital expenditures for chemical operations were up 4 percent between 1997 and 1998.

The other energy line of business, which is dominated by electric generation, cogeneration, and power marketing operations, had a decline in capital expenditures of 44 percent. This decline mainly reflected the absence in 1998 of Enron's 1997 acquisition of Portland General Electric for $3.0 billion. Capital expenditures of $1.5 billion in 1998 were, apart from 1997's outlays, the highest for other energy businesses in 16 years.

In the United States, Enron purchased a 1,000-megawatt gas-fired generating plant in New York.[Note 47] Sonat entered the power generation business with the purchase of a 50-percent interest in a 300-megawatt natural gas-fired unit in Georgia. Operations began in 1998. Sonat will also build a 680-megawatt natural gas-fired peaking plant in Georgia and will have a 50 percent ownership interest in the new plant.[Note 48] Coastal increased its ownership interest in Midland Cogeneration Venture Limited Partnership from 15.4 percent to 20.4 percent.[Note 49]

Internationally, Enron completed the acquisitions of UK utility assets from the ICI Group and of Elektro Electricidade e Servicos S.A. (Elektro), the sixth largest electricity distributor in Brazil (Table 8). The UK utility assets will allow Enron's wholly-owned subsidiary, Enron Teesside Operations Limited, to supply steam, water, power and other utility services to industrial customers in the United Kingdom.[Note 50] Coastal purchased a 67-percent interest in a 110-megawatt fuel-oil-fired power plant in Khulna, Bangladesh.[Note 51] Running against this trend was Unocal, which reported that expenditures declined due to the stoppage of geothermal exploratory and developmental drilling activity on the island of Sumatra in Indonesia and to the completion of its three new power plants. Unocal also announced that it reached an agreement to sell its geothermal steam operations at The Geysers in Northern California for $101 million to Calpine Corporation. The transaction is expected to close in 1999. [Note 52]

## Sources and Uses of Cash

The year 1998 was difficult not only in terms of massive reductions in net income and cash flow but additionally posed difficulties for the FRS companies' deployment of capital. The basic challenge was to adjust their sources and uses of cash in the face of capital expenditures that exceeded internal cash flow by $27 billion.

### Debt Reduction Wiped Out as Capital Expenditures Outrun Cash Flow

Capital expenditures of the FRS companies greatly exceeded cash flow from operations in 1998: the companies reported $75.1 billion in capital expenditures but only $48.2 billion in cash flow (Table 9). This was an extraordinary development in that the FRS companies' capital expenditures have generally, over the previous 24 years of FRS data collection, not exceeded their internally generated cash flow. Even in the context of the oil price crash of 1986, the FRS companies' capital expenditures were 10 percent below cash flow. In the 1990's, up to 1998, capital expenditures averaged 14 percent less than cash flow; however, in 1998, capital expenditures exceeded cash flow by 56 percent. For the companies that were in the FRS survey group in 1997 and 1998 (the "incumbents"), capital expenditures were up $7.1 billion but cash flow decreased $20.9 billion between the two years.

This mismatch between capital expenditure and cash flow levels raises at least two questions. How did the FRS companies make up the discrepancy? How might this disparity affect future investment outlays?

Several methods were used to close the capital expenditures-cash flow gap:

### *Borrow More*

The FRS companies utilize long-term debt (debt with a maturity greater than one year) as their primary source of external funds. In 1998, the FRS companies issued $9.2 billion more in long-term debt than in 1997. Of this amount, new FRS survey group members accounted for $6.3 billion and FRS incumbents accounted for the remaining $2.9 billion. However, this latter amount understates the incumbents' reliance on debt financing in 1998, in that DuPont, apart from its spun-off energy subsidiary Conoco, was in the FRS group in 1997 but not in 1998. DuPont was the leading issuer of debt among the FRS companies in 1997. Excluding DuPont (and Conoco), the remaining incumbents issued $7.9 billion more in long-term debt in 1998 than in 1997.

Cutting back debt reduction was another way that the FRS companies attempted to bridge the chasm between capital outlays and cash from operations. Until 1998, the FRS companies reduced the role of debt in their balance sheets through less debt financing and an increased pace of debt reduction. As a result, long-term debt relative to stockholders' equity, an often-used measure of the importance of debt in a company's balance sheet, declined from 60 percent to less than 40 percent in recent years, while for the S&P Industrials this ratio changed little (Figure 12). In 1998, FRS incumbents trimmed their debt reduction by $5.0 billion, which together with the increase in long-term borrowing in 1998, led to a climb in the FRS debt-equity ratio to nearly 50 percent, about the same value as in 1995.

### *Issue More Stock*

Companies in general, and FRS companies in particular, rarely issue stock simply to bridge short-term financing gaps. In most years, only a few FRS companies will issue additional equity shares beyond that earmarked for executive compensation and company retirement plans. In 1998, three companies--Conoco, Enron, and Sonat--accounted for the bulk of equity issued by FRS companies. Nevertheless, additional equity financing in 1998 contributed $7.6 billion to closing the gap between capital expenditures and cash flow ($7.3 billion from incumbents, $0.3 billion from new survey group companies).

### *Sell Assets*

Cash gained from asset sales by the FRS companies totaled $16.2 billion in 1998, the highest level ever. A majority of the companies reported an increase, compared to 1997, in proceeds from asset sales, perhaps reflecting an acceleration of planned consolidations of company operations. Shell Oil, for example, reported $1.2 billion from asset sales pursuant to restructuring its business focus, including its

$2.8-billion acquisition of Tejas Gas Corporation. ARCO reported $4.2 billion in cash from asset disposals in 1998, as the company sold its chemical operations and U.S. coal operations (Table 10),[Note 53] partly in order to finance its $3.3-billion acquisition of Union Texas Petroleum. Occidental Petroleum also used a combination of large acquisitions and divestitures to refocus its core competencies. The company sold its natural gas transmission subsidiary, MidCon, for $3.5 billion, while purchasing the U.S. Department of Energy's interest in the Elk Hills Naval Petroleum Reserve for $3.5 billion. Overall, FRS asset sales contributed an additional $6.9 billion to cash in 1998 compared to 1997.

### *Reduce Payouts to Shareholders*

Payouts to shareholders come in two forms. A company can repurchase its stock, thereby reducing the number of shares outstanding and increasing their value. Stock repurchases also put cash in the hands of shareholders, a usually welcome event. Although companies do announce stock repurchase programs, their implementation is discretionary and sporadic, often depending on recent trends in share values, available cash, and shifts in shareholder sentiments. In 1998, FRS incumbents reduced their outlays for stock repurchases by $2.5 billion.

In contrast, cash dividends paid to shareholders tend to show little volatility. The FRS companies steadily increased their dividends in the 1990's. In 1998, about as many incumbent FRS companies increased dividends as reduced them. On balance, this group reduced dividends $1.9 billion, or by 11 percent. This rare cutback in dividend payout was a reaction to diminished cash flow. In this context, it is notable that, although dividends were cut, the share of cash flow paid out as dividends in 1998, at 36 percent, was well above the average of 27 percent in the 1990's.

### *Draw Down Cash Balances*

In the sources and uses of cash shown in Table 9, the net change in cash measures the difference in cash on hand between the end of the year and the beginning of the year. In 1998, the FRS companies drew down their cash balances by $4.4 billion.

## Effects on Future Capital Outlays Uncertain

The unprecedented imbalance between cash flow and capital expenditures in 1998 could have a dampening effect on capital outlays in 1999. Debt reduction efforts by the FRS companies are likely to be resumed in order to reduce interest expense and thereby contribute to bottom-line net income. Nearly all of the FRS companies have a record in the 1990's of increasing, or at least maintaining, dividend payouts. In order to avoid shareholder discontent, companies will probably be reluctant to reduce dividends in 1999. If the FRS companies resume their earlier pace of debt reduction and modest, though steady, increases in dividend payout, then there will be pressures to reduce capital expenditures.

Plans for capital expenditures in 1999 and beyond were developed and adjusted in the context of sharply falling oil prices in 1998. Oil prices in December 1998 hit a low not seen since the onset of the first oil embargo in late 1973. Sharply lower oil prices and added stresses on cash flow appear to have had a substantial effect on the FRS companies' planned outlays for oil and gas exploration and development (E&D) for 1999 and possibly for the out years as well. In particular, information in an early 1999 survey by Salomon Smith Barney (published in June 1999)[Note 54] indicated that the FRS companies plan to cut their E&D expenditures (excluding mergers and acquisitions of already producing properties) for the United States by $5.4 billion and by $1.4 billion for foreign locales. Such cuts would represent a 28-percent reduction from 1998 outlays in the United States and a 7-percent reduction abroad.

The portents of these survey results should be set against the fact that since January 1999, oil prices have risen from $10 per barrel to $22 per barrel in October. Also, in response to cutbacks in drilling activity in 1998, the cost of adding to a company's oil and gas reserves has fallen, as rates charged by drilling and oil field service companies have been cut. Higher oil and gas prices and lower costs of adding reserves should, in part, offset the adverse effects of 1998's low oil prices and the imbalances between capital expenditures and internally generated cash flow.

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# Chapter 2 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 1998, 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. The entrant FRS firms for 1998 include Citgo Petroleum, Clark Refining & Marketing, Equilon Enterprises, Lyondell-Citgo Refining, Motiva Enterprises, Sunoco, Tesoro Petroleum, Tosco, Ultramar Diamond Shamrock, Valero Energy, and Williams Companies. Also, beginning with the 1998 reporting year, Ashland Oil was dropped from the FRS, Oryx merged with Kerr-McGee, and DuPont was dropped due to their spinoff of Conoco which remains an FRS respondent. BP America and Amoco continued to report separately in 1998 although BP and Amoco merged on December 31, 1998.
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 divestitutres of assets, provisions for the cost of restructuring, and provisions of reserves for future liabilities.
10. 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).
11. 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 measures ex-post average profitability, not marginal or prospective rates of return.
12. WEFA Group, *Asia Economic Outlook*, Fourth Quarter 1999 (October 1999), pp. SM.1 and SM.2.
13. 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 1974 through 1986, when income statement items were collected for chemical businesses by the FRS. Thus, the public disclosures of chemical segment revenue and operating

income were utilized for 1987 through 1998. 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.

14. Chevron Corp., 1998 Securities and Exchange Commission, Form 10K, p. FS-10.
15. USX Corporation, 1998 Securities and Exchange Commission, Form 10K, p. S-25.
16. Unocal Corp., *1998 Annual Report*, pp. 31, 76-77.
17. Exxon Corp., *1998 Annual Report*, pp. F5, F17-F18, and F24.
18. Enron Corp., *1998 Annual Report*, p. 35.
19. The Williams Companies, Inc., 1998 Securities and Exchange Commission, Form 10K, p. F-58.
20. The Coastal Corp., *1998 Annual Report*, p. 15.
21. Enron Corp., *1998 Annual Report*, pp. 32, 45.
22. Unocal Corp., *1998 Annual Report*, pp.30, 88.
23. Texaco Inc., 1998 Securities and Exchange Commission, Form 10K, pp. 17, 49.
24. A. T. Massey Coal, Arch Coal, BNI Coal, Consol Coal Group, Cyprus-Amax Coal, North American Coal, Peabody Holding Company, Pittston Coal, Western Energy, Westmoreland Coal, Wyodack Resources.
25. 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.
26. 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 1998, additions to PP&E accounted for 94 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.
27. 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 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 the FRS company Chevron (then Standard Oil of California) purchased Gulf Oil, also 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.
28. Figure 9 and Table 7 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 8 can differ from the effect on additions to investment in place due to assumptions of liabilities and goodwill assets acquired.
29. Occidental Petroleum Corp., *98 Report to Stockholders*.
30. Union Pacific Resources Group, Press Release, January 26, 1998.
31. USX Corp., Press Release, May 29, 1998.
32. ARCO, Press Release, May 4, 1998.
33. Shell Oil Company, News Release, April 30, 1998.
34. "Reserves off Angola climb to 8 Billion Barrels as Major Firms Find Success in Deepwater," *The Oil Daily*

(October 29, 1999), p. 4.

35. Chevron Corp., *Supplement to the 1998 Annual Report*, p. 23, and Phillips Petroleum Corp., 1998 Securities and Exchange Commission, Form 10K, p. 11.
36. Texaco Inc., 1998 Securities and Exchange Commission, Form 10K, p. 9 and *1998 Annual Report*, p. 20.
37. Exxon Corp., 1998 Securities and Exchange Commission, Form 10K, p. 6 and *1998 Annual Report*, p. 8.
38. Amerada Hess Corp., *1998 Annual Report*, pp. 9-11.
39. ARCO, *1998 Annual Report*, pp. 8, 52.
40. Exxon Corp., *1998 Annual Report*, p. 8.
41. Conoco, Inc., 1998 Securities and Exchange Commission, Form 10K, p. 5.
42. Coastal Corp., *1998 Annual Report*, p. 9.
43. The number of wells initiated is equal to the number of wells completed plus the change in the number of wells-in-progress. See Table B-19.
44. USX Corp., 1998 Securities and Exchange Commission, Form 10K, p. M-29.
45. Exxon Corp., *1998 Annual Report*, p. 13.
46. Coastal Corp., *1998 Annual Report*, p. 27.
47. Enron Corp., *1998 Annual Report*.
48. Sonat Corp., *1998 Annual Report*.
49. Coastal Corp., "Coastal Acquires Additional Stake in Midland Cogeneration Venture," Press Release, June 16, 1998, p. 1.
50. The acquisiton of Elektro totaled nearly $1.3 billion and the utility assets from the ICI Group were acquired for $500 million. Enron Corporation, *1998 Annual Report*, pp. 52 and 57.
51. Coastal Corp., *1998 Annual Report*.
52. Unocal Corp., *1998 Annual Report*.
53. Although the value of ARCO's sale of shares in ARCO Chemical Company was $4.6 billion, the company reported that after-tax cash proceeds were $3.0 billion (ARCO, Press Release (June 18, 1998)).
54. Salomon Smith Barney, *1999 E&P Spending Survey: Midyear Update* (July 7, 1999).

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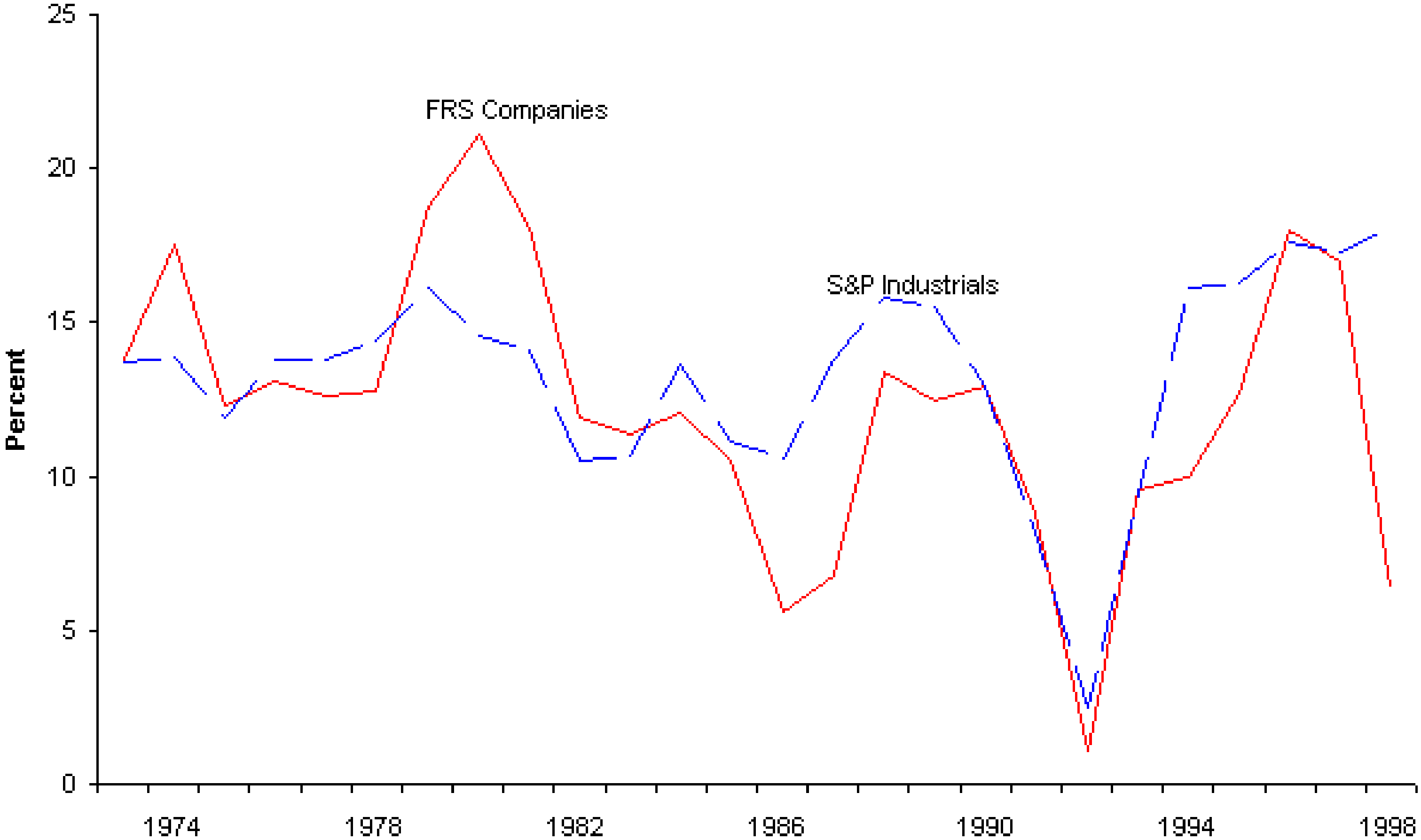
**Figure 4. Return on Equity for FRS Companies and the S&P Industrials, 1973-1998**




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.

**Table 2**
**Consolidated Income Statement for FRS Companies and the S&P Industrials, 1997 and 1998**
(Billion Dollars)

| | FRS Companies | | | | | S&P Industrials | | |
|---|---|---|---|---|---|---|---|---|
| **Income Statement Items** | **1997** | **1998** | **Percent Change 1997-1998** | **Incumbents[a] 1998** | **Percent Change 1997-1998** | **1997** | **1998** | **Percent Change 1997-1998** |
| Operating Revenues | 525.1 | 484.2 | -7.8 | 398.2 | -24.2 | 3,787.0 | 3,923.5 | 3.6 |
| Operating Expenses | -478.4 | -468.3 | -2.1 | -384.6 | -19.6 | -3,352.1 | -3,502.6 | 4.5 |
| Operating Income | 46.7 | 15.8 | -66.0 | 13.6 | -70.9 | 434.9 | 420.9 | -3.2 |
| Interest Expense | -6.4 | -7.3 | 14.2 | -6.1 | -4.1 | -77.1 | -80.6 | 4.5 |
| Other Revenue (Expense) | 10.4 | 8.7 | -17.0 | 8.1 | -22.6 | -1.6 | 35.5 | -- |
| Income Tax Expense | -18.6 | -4.7 | -74.7 | -4.3 | -76.8 | -129.8 | -120.6 | -7.1 |
| Net Income | 32.1 | 12.5 | -61.0 | 11.2 | -65.0 | 226.4 | 255.1 | 12.7 |
| Net Income Excluding Unusual Items | 33.9 | 19.5 | -42.4 | 17.5 | -48.3 | NA | NA | |

[a] Companies reporting in 1997 and 1998.

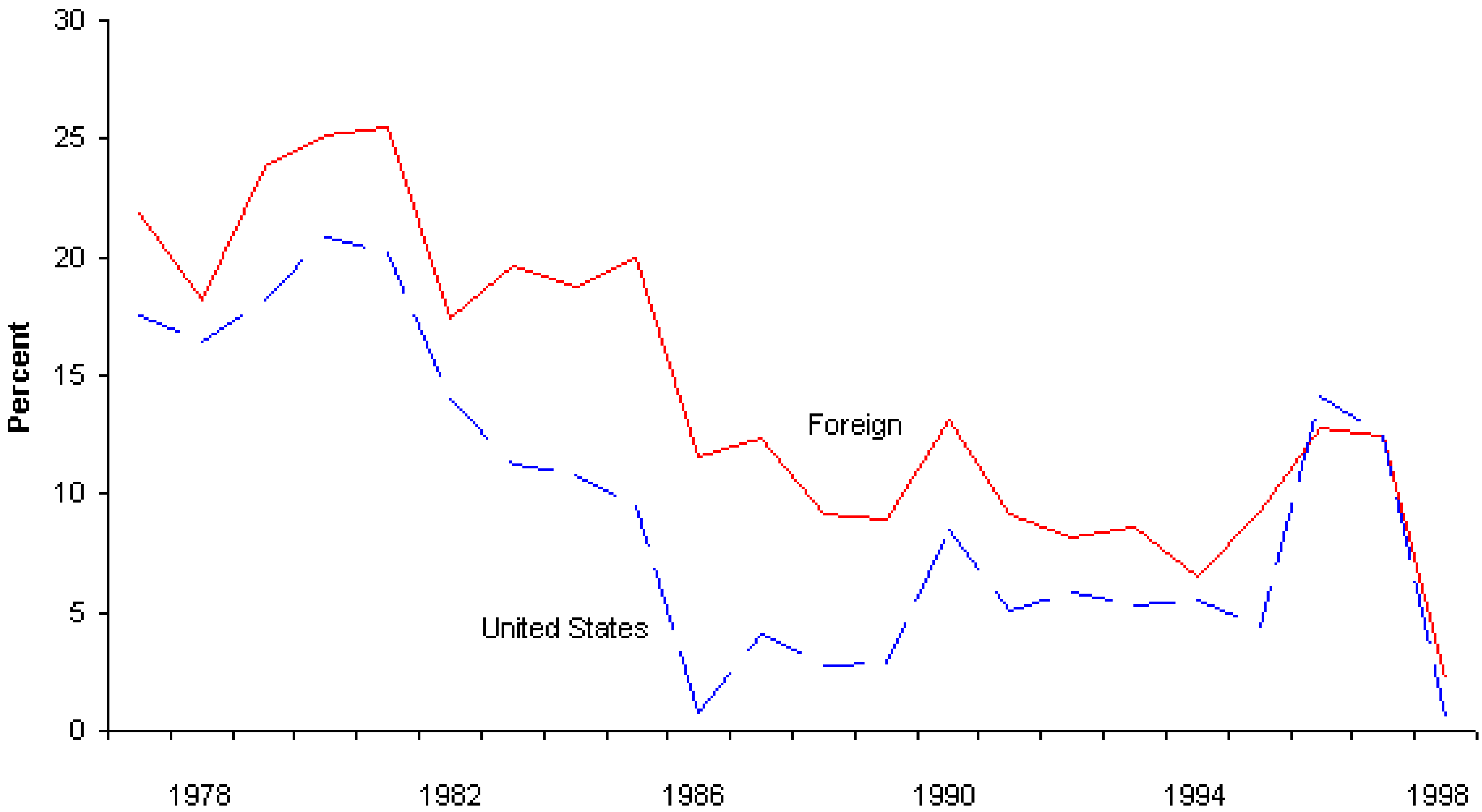
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data. NA = not available.

-- = not meaningful

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.

*Last Updated on 12/2/99*

**Figure 5. Return on Investment in U.S. and Foreign Oil and Gas Production for FRS Companies, 1977-1998**




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

**Table 3**
**Contributions to Net Income by Line of Business for FRS Companies,1997-1998**
(Million Dollars)

| Line of Business | Net Income 1997 | Net Income 1998 | Net Income Percent Change 1997-1998 | Net Income Excluding Unusual Items 1997 | Net Income Excluding Unusual Items 1998 | Percent Change 1997-1998 | Incumbents[b] 1998 | Percent Change 1997-1998 |
|---|---|---|---|---|---|---|---|---|
| Petroleum | | | | | | | | |
| U.S. Petroleum | | | | | | | | |
| Production | 11,552 | 485 | -95.8 | 11,436 | 3,170 | -72.3 | 2,931 | -74.4 |
| Refining/Marketing | 3,106 | 5,904 | 90.1 | 3,285 | 6,943 | 111.4 | 4,936 | 50.3 |
| Pipelines | 1,326 | 1,352 | 2.0 | 1,867 | 2,022 | 8.3 | 1,483 | -20.6 |
| Total U.S. Petroleum | 15,984 | 7,741 | -51.6 | 16,588 | 12,135 | -26.8 | 9,350 | -43.6 |
| Foreign Petroleum | | | | | | | | |
| Production | 9,550 | 2,030 | -78.7 | 8,839 | 4,423 | -50.0 | 4,438 | -49.8 |
| Refining/Marketing | 3,583 | 2,945 | -17.8 | 3,935 | 3,667 | -6.8 | 3,639 | -7.5 |
| International Marine | 138 | 93 | -32.6 | 138 | 93 | -32.6 | 93 | -32.6 |
| Total Foreign Petroleum | 13,271 | 5,068 | -61.8 | 12,912 | 8,183 | -36.6 | 8,170 | -36.7 |
| Total Petroleum | 29,255 | 12,809 | -56.2 | 29,500 | 20,318 | -31.1 | 17,520 | -40.6 |
| Coal | 338 | 500 | 47.9 | 379 | 224 | -40.9 | 168 | -55.7 |
| Other Energy | 346 | 346 | 0.0 | 336 | 947 | 181.8 | 947 | 181.8 |
| Nonenergy | 6,291 | 1,831 | -70.9 | 8,259 | 2,222 | -73.1 | 1,715 | -79.2 |
| Total Allocated | 36,230 | 36,309 | 0.2 | 38,474 | 23,711 | -38.4 | 20,993 | -45.4 |
| Nontraceables and Eliminations | -4,148 | -4,227 | -- | -4,578 | -4,201 | -- | -3,474 | -24.1 |
| Consolidated Net Income[a] | 32,082 | 12,519 | -61.0 | 33,896 | 19,510 | -42.4 | 17,519 | -48.3 |

[a]The total amount of unusual items was -$1,814 million and -$6,991 million in 1997 and 1998, respectively.

[b]Companies reporting in 1997 and 1998.

-- = Not meaningful.

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

*Last Updated on 12/2/99*

**Table 4**
**Return on Investment by Line of Business for FRS Companies, 1988-1998**
(Percent)

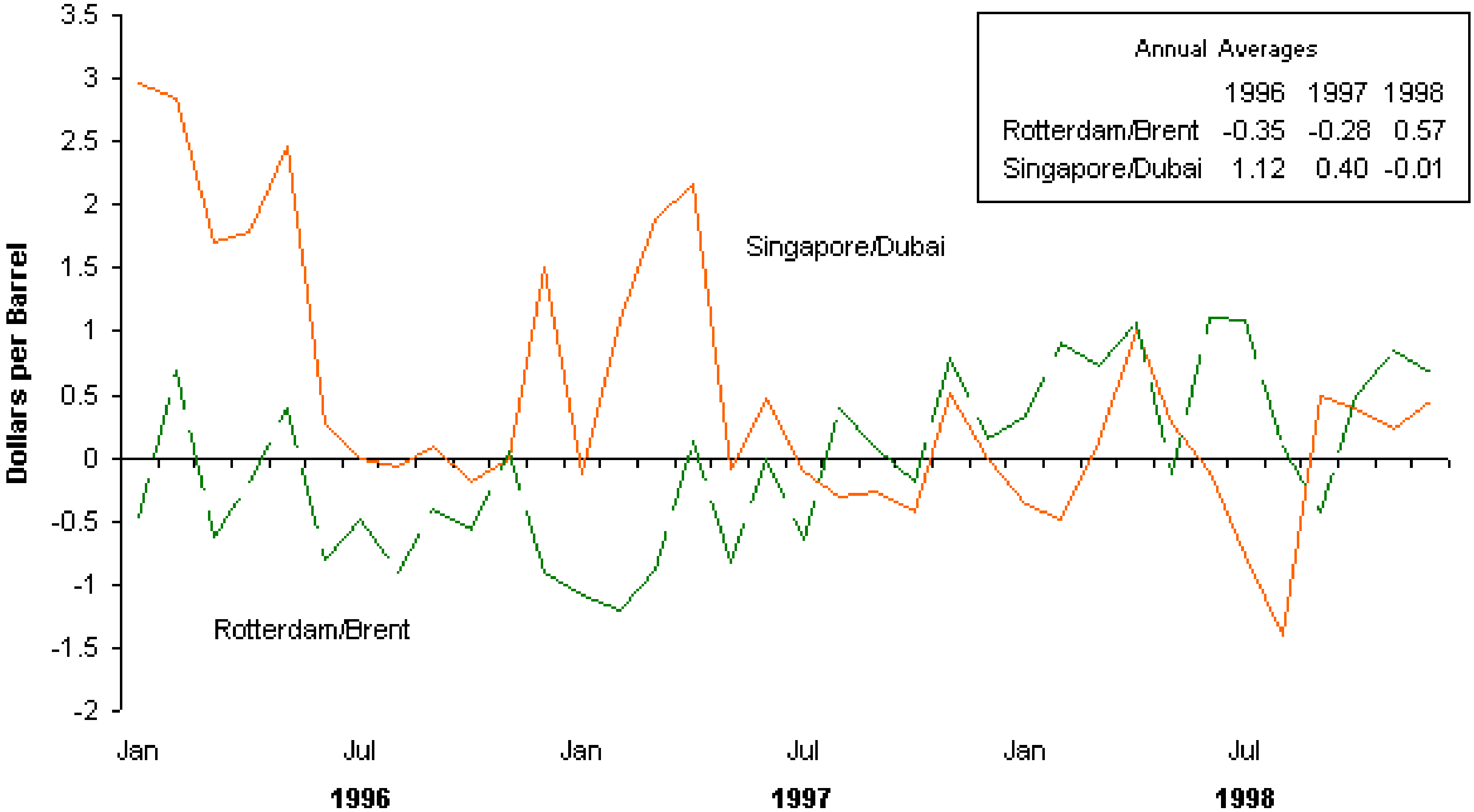
| Line of Business | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Petroleum | 7.3 | 6.7 | 9.5 | 7.0 | 5.6 | 6.4 | 5.6 | 5.7 | 10.1 | 10.8 | 3.9 |
| U.S. Petroleum | 6.3 | 5.8 | 7.9 | 4.9 | 4.4 | 4.9 | 5.2 | 4.0 | 9.9 | 10.0 | 3.8 |
| Oil and Gas Production | 2.8 | 2.9 | 8.5 | 5.1 | 5.9 | 5.3 | 5.5 | 4.4 | 14.1 | 12.5 | 0.5 |
| Refining/Marketing | 14.7 | 11.5 | 5.1 | 2.0 | -0.4 | 3.4 | 3.6 | 1.0 | 4.4 | 6.6 | 7.9 |
| Pipelines | 9.6 | 10.2 | 11.2 | 10.7 | 8.4 | 6.4 | 7.6 | 9.1 | 6.9 | 6.7 | 4.4 |
| Foreign Petroleum | 9.9 | 8.7 | 12.5 | 11.0 | 7.9 | 9.2 | 6.2 | 8.4 | 10.6 | 11.9 | 4.0 |
| Oil and Gas Production | 9.2 | 8.9 | 13.1 | 9.1 | 8.2 | 8.6 | 6.5 | 9.3 | 12.8 | 12.5 | 2.2 |
| Refining/Marketing | 11.6 | 8.0 | 11.2 | 14.6 | 7.8 | 10.6 | 6.1 | 7.2 | 6.0 | 10.5 | 8.2 |
| International Marine | 6.8 | 12.4 | 11.7 | 15.6 | -1.2 | 1.2 | -2.0 | -2.5 | 2.2 | 11.8 | 8.9 |
| Coal | 6.7 | 5.0 | 3.3 | 8.7 | -9.3 | 7.6 | 4.0 | 6.9 | 9.9 | 7.2 | 25.7 |
| Other Energy | -2.5 | -2.3 | 2.6 | 2.8 | 1.8 | 4.1 | 4.8 | 6.1 | 7.9 | 7.0 | 13.2 |
| Nonenergy | 20.3 | 17.3 | 7.8 | 2.9 | 2.1 | 4.7 | 10.5 | 19.4 | 15.0 | 10.9 | 4.5 |

Note: Return on investment measured as contribution to net income/net investment in place.

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

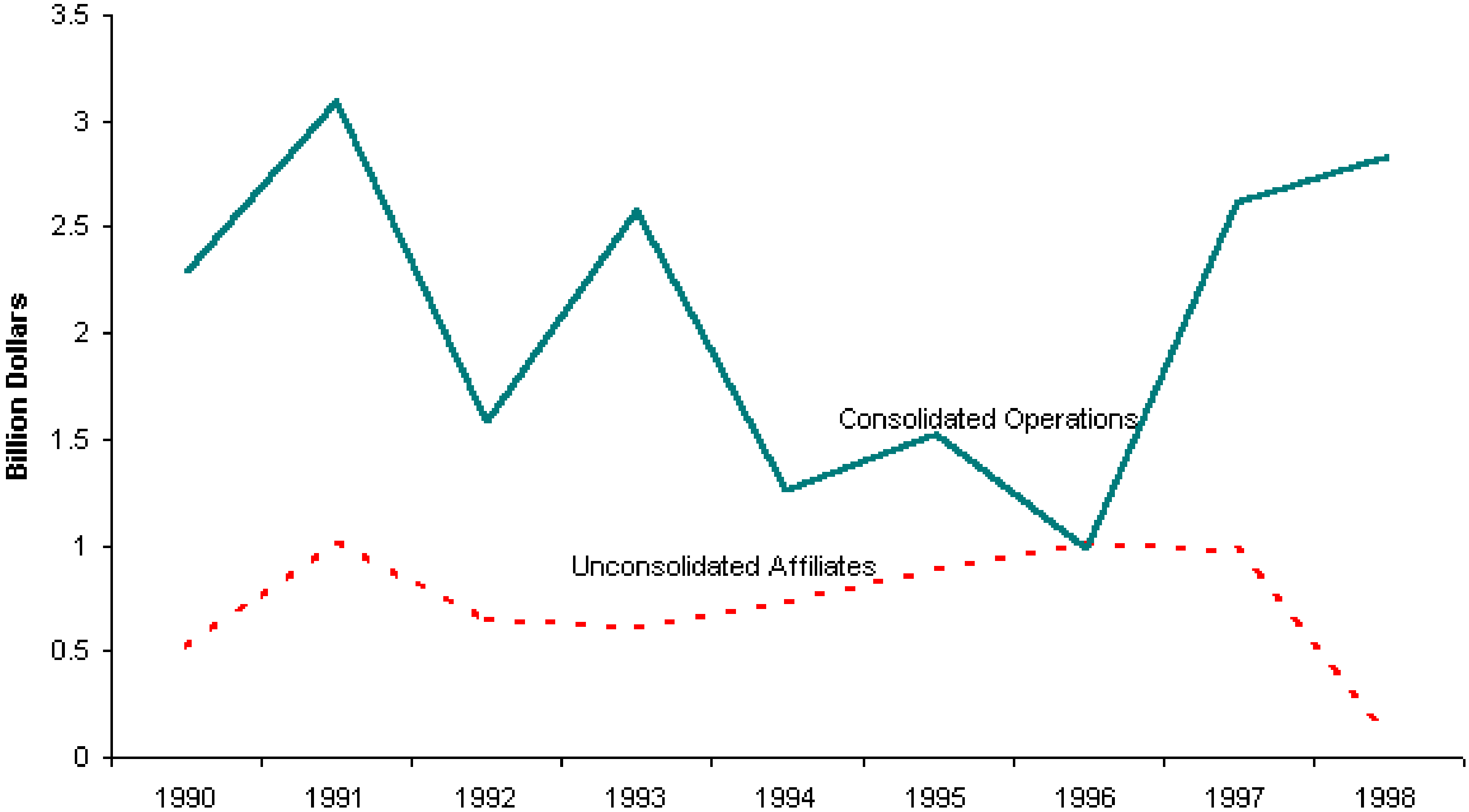
*Last Updated on 12/2/99*

**Figure 6. Foreign Refining Margins, 1996-1998**



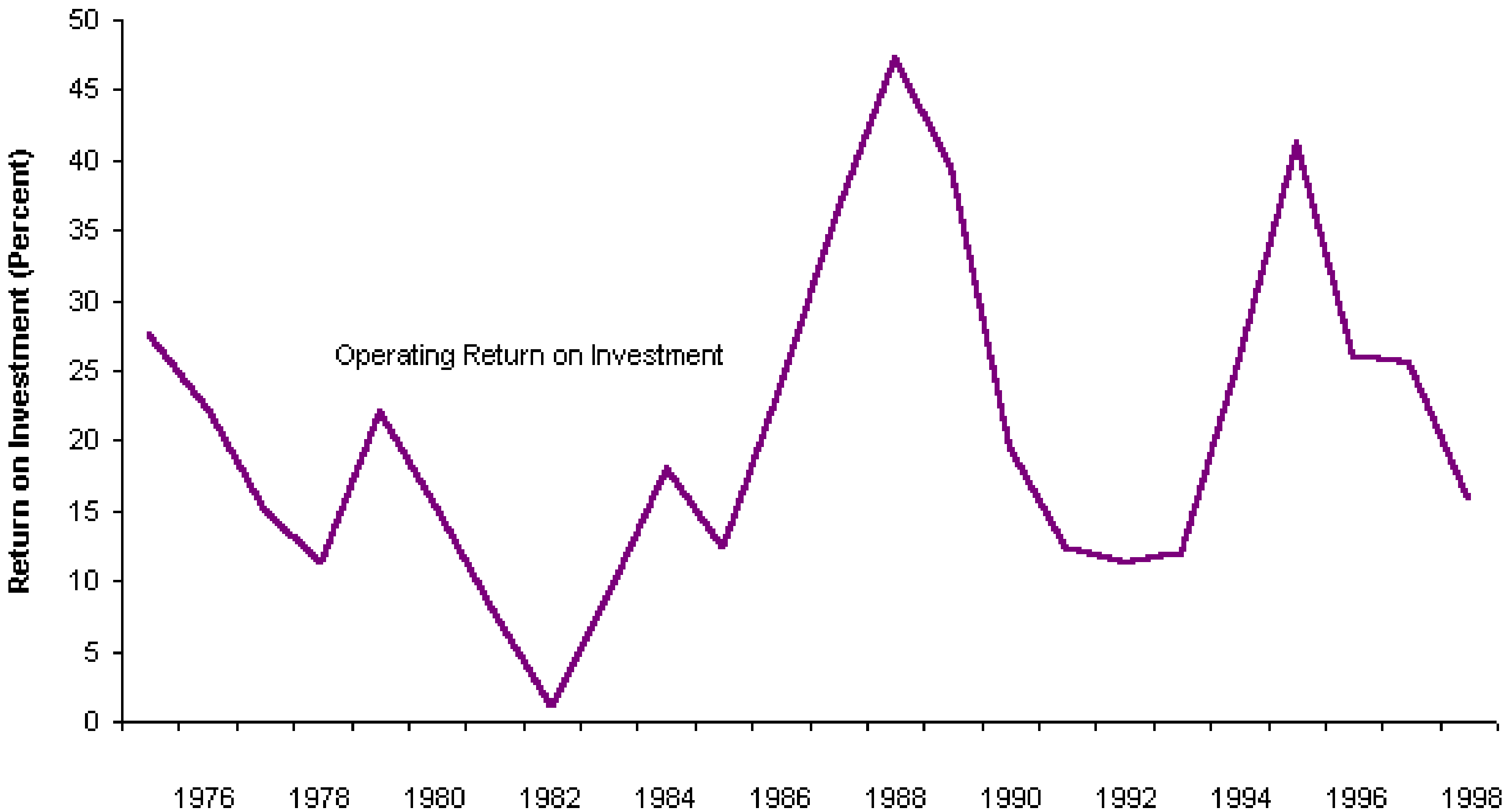

Note: Refining margin is defined as netback crude oil price less spot crude oil price. Netback price is calculated by multiplying the spot price of each refined product by the percentage share in the yield of a barrel of crude oil. Transport and out-of-pocket refining costs are then subtracted to arrive at netback price. Sources: **1998**: *Oil Market Intelligence* (January 1999 and July 1998), p. 12; **1997**: *Oil Market Intelligence* (January 1999 and July 1998), p. 12; and **1996**: *Petroleum Market Intelligence*, Vol. 8, No. 12 (January 4, 1997), p. 8.

**Figure 7. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates for FRS Companies, 1990-1998**




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

**Figure 8. Operating Return on Investment in Chemicals for FRS Companies, 1975-1998**




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 5**
**Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1997-1998**
(Million Dollars)

| Segment | 1997 | 1998 | Percent Change 1997-1998 |
|---|---|---|---|
| **Operating Income, Excluding Unusual Items** | | | |
| Chemicals | 10,404 | 4,037 | -61.2 |
| Other Nonenergy | 706 | -527 | -174.6 |
| For Companies Reporting in 1997 and 1998 | | | |
| Chemicals | 5,867 | 3,956 | -32.6 |
| Other Nonenergy | 540 | -352 | -165.2 |

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.

*Last Updated on 12/2/99*

**Table 6.**
**Line of Business Contributions to Pretax Cash Flow for FRS Companies, 1997-1998**
(Billion Dollars)

| Contribution to Pretax Cash Flow [a] | 1997 | 1998 | Percent Change 1997-1998 | Incumbents[b] 1998 |
|---|---|---|---|---|
| Petroleum | | | | |
| Oil and Gas Production | 51.5 | 29.0 | -43.6 | 28.5 |
| Refining, Marketing, and Transport | 16.4 | 21.2 | 29.5 | 16.7 |
| Coal and Other Energy | 1.3 | 1.2 | -3.9 | 1.1 |
| Chemicals | 11.1 | 5.5 | -50.0 | 5.4 |
| Other Nonenergy | 1.4 | 0.0 | -98.2 | 0.1 |
| Nontraceable | -3.1 | -3.2 | -- | -3.1 |
| Total Contribution to Pretax Cash Flow[a] | 78.3 | 53.8 | -31.3 | 48.9 |
| Current Income Taxes | -16.2 | -5.8 | -64.1 | -5.7 |
| Other (Net) | 3.2 | 0.2 | -94.9 | 1.3 |
| Cash Flow from Operations | 65.3 | 48.2 | -26.3 | 44.4 |

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

[b]Companies reporting in 1997 and 1998.

-- = 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).

*Last Updated on 12/9/99*

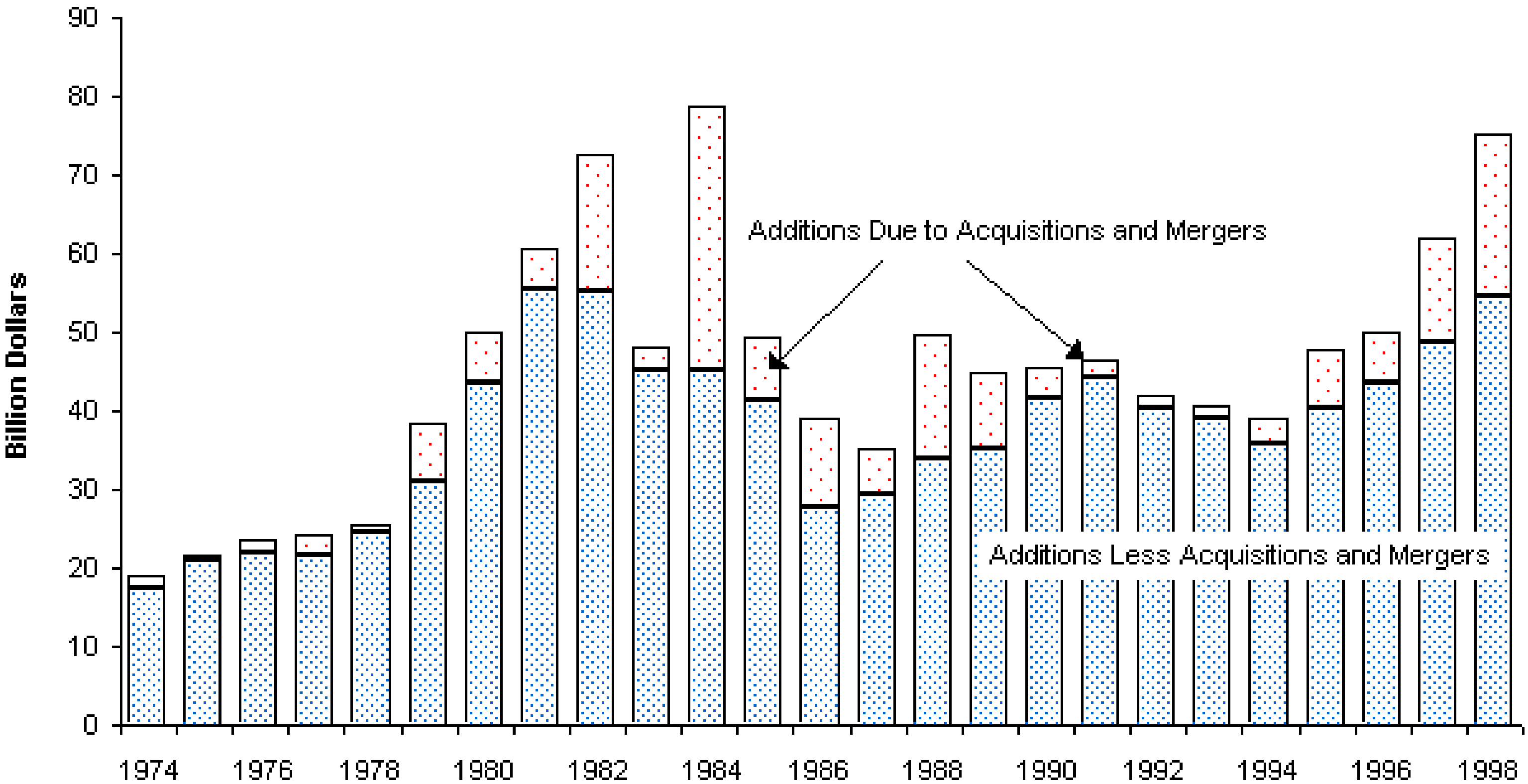
**Table 7. Additions to Investment in Place by Line of Business for FRS Companies, 1997-1998**
(Billion Dollars)

| Line of Business | 1997 | 1998 | Percent Change 1997-1998 | Percent Change Excluding Merger and Acquisitions 1997-1998 |
|---|---|---|---|---|
| Petroleum | | | | |
| U.S. Petroleum | | | | |
| Production | 20.2 | 22.3 | 10.4 | 1.5 |
| Refining/Marketing | | | | |
| Refining | 1.7 | 4.4 | 161.2 | 99.6 |
| Marketing | 2.2 | 2.7 | 19.8 | 22.7 |
| Transport | 0.7 | 1.1 | 58.3 | 58.3 |
| Total Refining/Marketing | 4.6 | 8.2 | 77.7 | 56.8 |
| Pipelines | 1.7 | 5.4 | 208.4 | 32.2 |
| Total U.S. Petroleum | 26.6 | 35.9 | 35.2 | 15.7 |
| | | | | |
| Foreign Petroleum | | | | |
| Production | 16.9 | 26.1 | 54.1 | 29.4 |
| Refining/Marketing | 3.5 | 3.5 | 1.6 | 15.3 |
| International Marine | 0.0 | 0.0 | 18.5 | -- |
| Total Foreign Petroleum | 20.4 | 29.6 | 45.1 | 26.3 |
| | | | | |
| Total Petroleum | 47.0 | 65.5 | 39.5 | 20.4 |
| Coal | 0.4 | 0.2 | -49.4 | -49.4 |
| Other Energy | 2.8 | 1.5 | -44.0 | -12.3 |
| Nonenergy | | | | |
| Chemicals | 9.1 | 5.2 | -42.5 | -14.5 |
| Other Nonenergy | 1.1 | 2.6 | 146.5 | 57.5 |
| Total Nonenergy | 10.2 | 7.8 | -22.8 | -3.5 |
| Nontraceables | 1.6 | 0.0 | -99.3 | -- |
| Additions to Investment in Place[a] | 61.9 | 75.1 | 21.3 | -- |
| Additions Due to Mergers and Acquisitions | 13.2 | 20.7 | 57.0 | -- |
| Total Additions Excluding Mergers and Acquisitions | 48.7 | 54.4 | 11.7 | -- |
| Addendum: Environmental Capital Expenditures | 2.3 | 2.0 | -14.6 | -- |

[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.

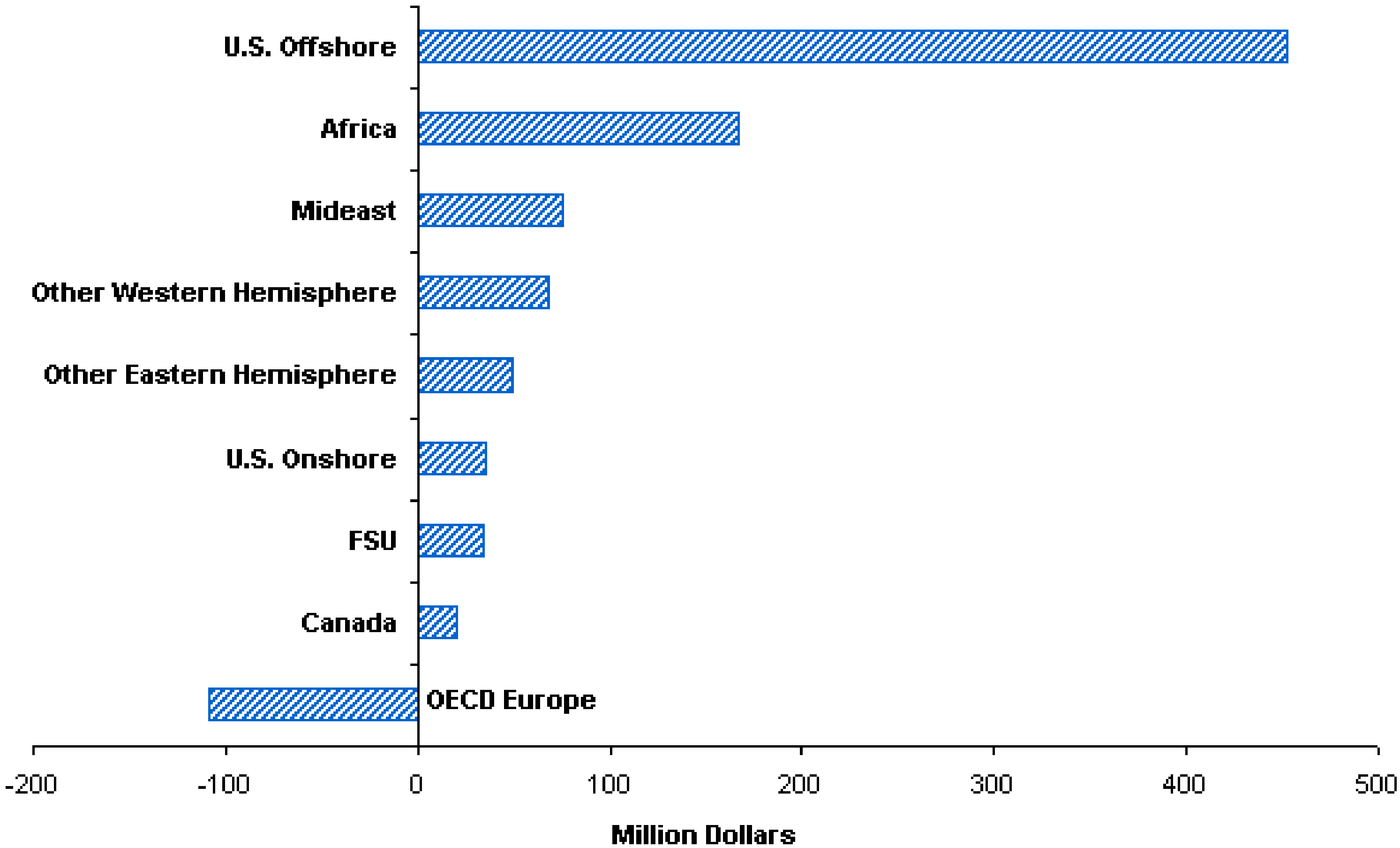
*Last Updated on 12/15/99*

**Figure 9. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-1998**




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

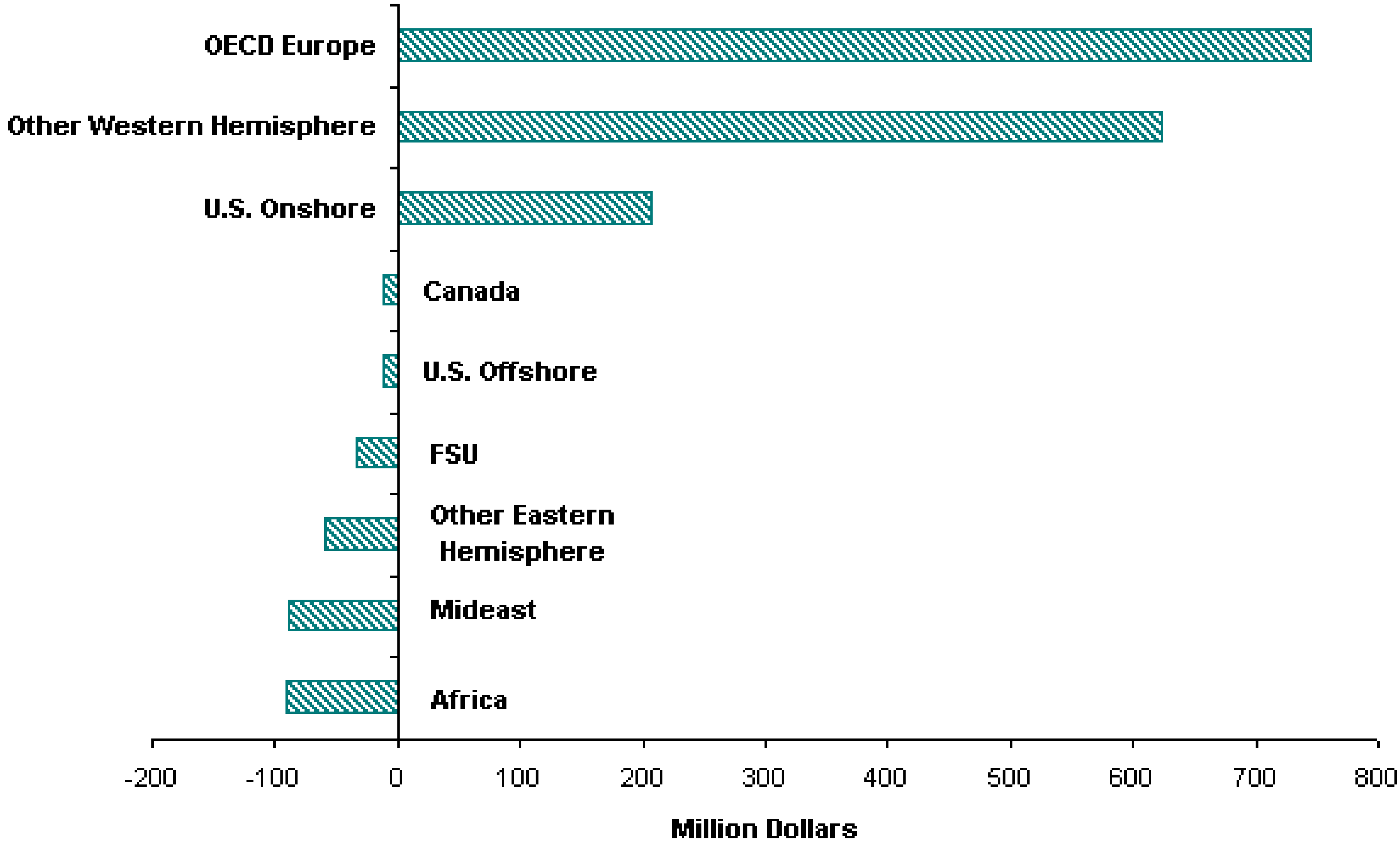
**Figure 10. Change in Exploration Expenditures (excluding unproved acreage) by Region for FRS Companies, 1997-1998**




Note: FSU = Former Soviet Union.

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

Figure 11. Change in Development Expenditures (excluding proved acreage) by Region for FRS Companies, 1997-1998




Note: FSU = Former Soviet Union.

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

**Table 8.**
**Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1998**
(Million Dollars)

| Line of Business and Acquiring Company | Acquisition | Reported Value of Acquisition |
|---|---|---|
| **U.S. Oil and Gas Production** | | |
| Occidental Petroleum | Elk Hills Naval Petroleum Reserve from the US Dept. of Energy | 3,500 |
| Sonat | Zilkha Energy | 1,300 |
| Coastal | Conoco's interests in 21 oil and gas fields in Utah and Colorado | 200 |
| Enron | Interest in Gulf of Mexico property from Union Pacific | 158 |
| Shell Oil | Acquisition of 39.9-percent stake in Meridian Resource Group | 135 |
| Anadarko Petroleum | Occidental Petroleum's interest in Oklahoma properties | 118 |
| **Foreign Oil and Gas Production** | | |
| ARCO | Union Texas Petroleum | 3,300 |
| Union Pacific Resources | Norcen Energy Resources (Canada) | 2,634 |
| USX | Acquisition of Tarragon Oil and Gas (Canada) | 1,160 |
| Kerr-McGee | North Sea assets from Gulf Canada Resources | 422 |
| Unocal | Interests in Tarragon Oil and Gas, LTD | 212 |
| ARCO | 25-percent interest in a major natural gas project in the Malaysia-Thailand Joint Development Area | 150 |
| **U.S. Refining/Marketing** | | |
| Valero Energy | Paulsboro, New Jersey refinery from Mobil | 336 |
| Tesoro Petroleum | Shell Oil refinery at Anacortes, Washingon | 280 |
| Tesoro Petroleum | Hawaiian refining and marketing assets of Broken Hill Proprietary | 270 |
| Clark Refining & Marketing | BP America's Lima, Ohio refinery | 175 |
| Sunoco | Allied Signal's phenol facility in Philadelphia | 157 |
| **Other Energy** | | |
| Enron | Utility assets from the ICI Group (United Kingdom) | 500 |
| Enron | Elektro Electricidade e Servicos (Brazil) | 447 |
| **Pipelines** | | |
| Shell Oil | Tejas Gas Corporation | 2,800 |
| **Other Nonenergy** | | |
| Enron | Wessex Water (United Kingdom) | 918 |
| Sources: Company annual reports to shareholders and press releases. | | |

*Last Updated on 12/15/99*

**Table 9.**
**Sources and Uses of Cash for FRS Companies, 1997-1998**
(Billion Dollars)

| Sources and Uses of Cash | 1997 | 1998 | Percent Change 1997-1998 | Incumbents[a] 1998 |
|---|---|---|---|---|
| Main Sources of Cash | | | | |
| Cash Flow from Operations | 65.3 | 48.2 | -26.3 | 44.4 |
| Proceeds from Long-Term Debt | 17.9 | 27.1 | 51.2 | 20.7 |
| Proceeds from Disposals of Assets | 9.3 | 16.2 | 74.3 | 15.4 |
| Proceeds from Equity Security Offerings | 1.5 | 9.1 | 504.6 | 8.8 |
| Main Uses of Cash | | | | |
| Additions to Investment in Place | 61.9 | 75.1 | 21.3 | 69.0 |
| Reductions in Long-Term Debt | 19.8 | 18.0 | -8.9 | 14.8 |
| Dividends to Shareholders | 16.9 | 17.2 | 1.3 | 15.0 |
| Purchase of Treasury Stock | 7.9 | 5.8 | -27.0 | 5.4 |
| Other Investment and Financing Activities, Net | 11.9 | 11.1 | -- | 10.0 |
| Net Change in Cash and Cash Equivalents | -0.6 | -4.4 | -- | -4.8 |

[a] Companies reporting in 1997 and 1998.

-- = Not meaningful.

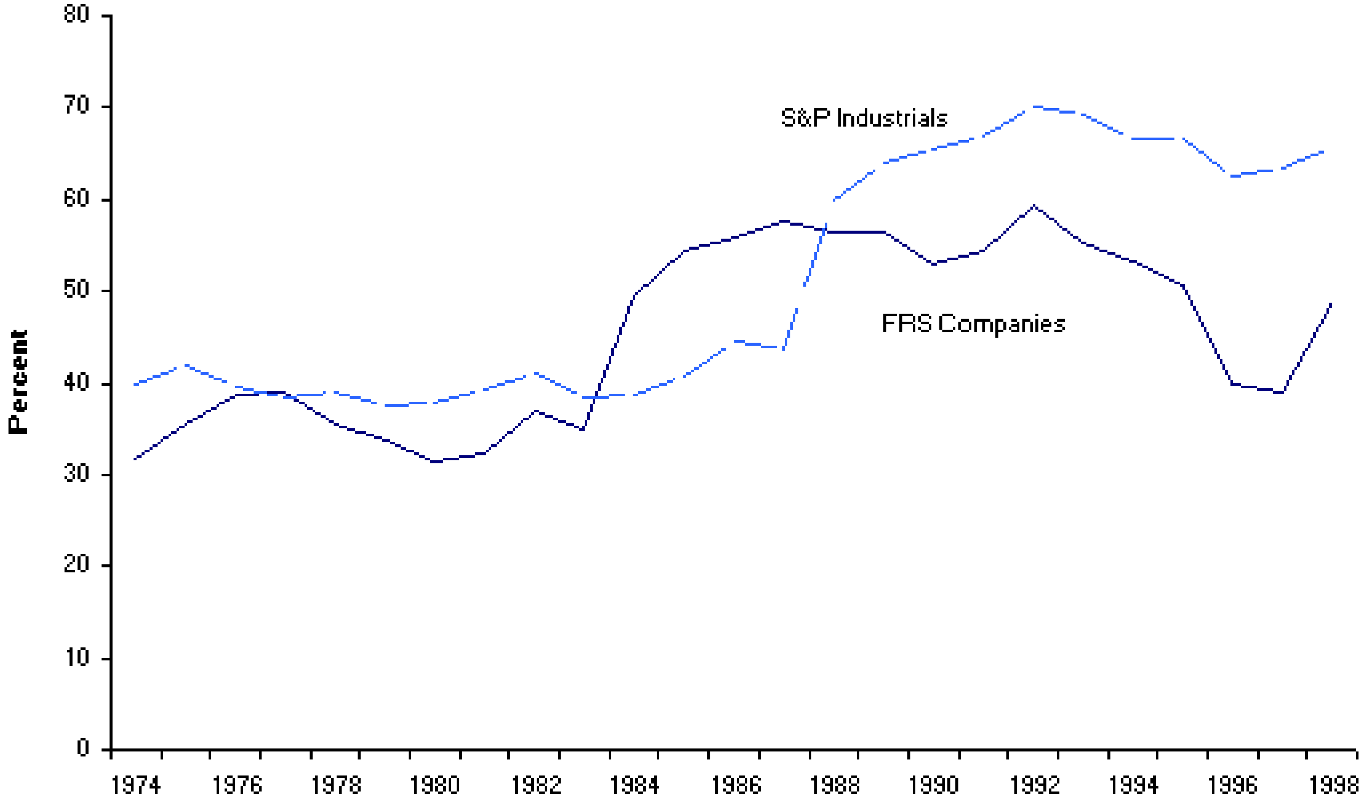
Note: Sources minus Uses plus Other Investment and Financing Activities (Net) may not equal Net Change in Cash and Cash Equivalents due to independent rounding.

Percent changes were calculated from unrounded data.

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

*Last Updated on 12/15/99*

**Figure 12. Long-term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-1998**




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.

# 3. BEHIND THE BOTTOM LINE

## Oil and Gas Production

### Oil and Gas Profitability at an All-Time Low

The profitability of the FRS companies in 1998 was at its lowest level in the 22 years that these data have been collected (Figure 5 in Chapter 2). The low profitability is in contrast to results for 1996 and 1997, when upstream rates of return surged to heights not seen since the era of high oil prices, which ended in 1985.

The comedown in financial performance was mostly attributable to lower oil prices in 1998; the FRS companies' crude oil prices were down 34 percent in the United States and 36 percent abroad (Table 11). Natural gas prices were not as strongly affected by market developments in 1998, registering less steep declines of 15 percent in the United States and 6 percent outside the United States.

In the United States, the effect of lower oil prices was amplified by the FRS companies' 5-percent cut in oil production and reduced natural gas sales. Revenues from U.S. oil and gas production were down $16.7 billion in 1998 (Table 12). The plunge in revenues was not wholly reflected in income, as the FRS companies were able to reduce lifting costs by $1 billion. (Lifting costs include production taxes, while direct lifting costs exclude production taxes.) The reduction in lifting costs was largely tax-driven, as production taxes are frequently levied as a percentage of wellhead revenues. When wellhead prices decline, production tax collections decline. In 1998, the FRS companies' U.S. production tax per barrel of oil and gas was down 39 percent from 1997. Direct lifting costs in the United States declined, as well. The FRS companies managed to make a slight cut in direct lifting costs in 1998, as they have in every year since 1991 (Figure 13 and, for a more detailed regional review of lifting costs, see the next section).

In foreign oil and gas production, revenues did not fall as steeply, as the FRS companies increased their oil production abroad by 5 percent and natural gas production abroad by 7 percent (Table 11). (See also the section in this chapter, "1998 Production of Oil and Gas by FRS Companies Declined Only in Asia-Pacific and U.S. Onshore.") As in the United States, reduced production taxes supplied only a slight offset to the effects of lower oil and gas prices.

A more subtle effect of lower oil and gas prices in 1998 was the unusually large increase in depreciation, depletion, and amortization expense (DD&A) (Table 12). This expense item represents an allowance for the deterioration in value of physical assets over time. In addition, financial accounting standards applicable to the oil and gas industry require a company's asset values to be reduced when oil and gas prices decline if the value of estimated future cash flows from the assets, based on the lower prices, are less than the value of the assets carried on the company's balance sheet. The reduction in value is called an "asset impairment" and is recognized as a charge against income. It is usually included in DD&A and/or other operating expense. In 1998, 18 FRS companies reported such charges, which reduced worldwide operating income from oil and gas production by $8.3 billion.

### Lifting Costs Continue to Decline

Lifting costs (production costs) are the out-of-pocket costs, including production taxes, to operate and maintain wells and related equipment and facilities after hydrocarbons have been found, acquired, and developed for production. Direct lifting costs for the FRS companies have been falling, albeit at a decreasing rate, since the early 1990's (Figure 13). Several factors account for this decline, including improved operating practices (such as the consolidation of producing properties) and improved technology (such as the use of new materials and computerized information technologies). Direct lifting costs in the United States and overseas converged around 1991, and have followed similar paths since then. One possible explanation for this convergence is that the FRS companies have been operating increasingly overseas and have more fully integrated their operations worldwide, collapsing some differences between U.S. and foreign operations.

Direct lifting costs declined slightly in the United States in 1998 (Table 13). Overseas, direct lifting costs declined or rose only slightly in all regions except Africa. The increase in Africa may in part reflect the increased emphasis on the deep-water areas off West Africa, where production costs appear to be higher. Direct lifting costs in the Former Soviet Union and Eastern Europe, which are available publicly for the FRS companies for the first time this year, appear much higher than for the other regions. This may be the result of the small amount of FRS production there and/or the newness of FRS operations there.

### 1998 Production of Oil and Gas by FRS Companies Declined Only in Asia-Pacific and U.S. Onshore

Despite the collapse of oil prices in 1998, growth in the worldwide production of oil (crude oil and natural gas liquids) by the FRS companies was flat, while the worldwide production of dry natural gas rose 3 percent (Table 14).[Note 55] Oil production by the FRS companies rose in all regions of the world except the U.S. onshore and Asia-Pacific. Oil production in the U.S. onshore region fell by 105 million barrels, a 10-percent decline, and in the Asia-Pacific region by 15 million barrels. The U.S. onshore decline was in part the result of decreased oil production by Atlantic Richfield. Natural field declines in its Alaska operations plus the exchange of heavy crude oil producing properties in California for exploration acreage and producing properties in the Gulf of Mexico diminished its onshore production.[Note 56] In addition, Shell Oil sold substantially all of its southern Louisiana onshore properties in 1998 and entered into two joint ventures in the Permian Basin and California in 1997, to which it contributed its producing assets from those areas.[Note 57,Note 58] The Asia-Pacific decline was the result of small production decreases spread across various companies and is likely attributable to the Asia-Pacific economic crisis in 1998.

The FRS companies made notable increases in oil production in 1998 in the Former Soviet Union and Eastern Europe, the Middle East, and Canada. In the Former Soviet Union and Eastern Europe, the number of FRS producing companies increased from 2 to 5 between 1997 and 1998, and accounted for nearly all of the increase in oil production for the combined Europe and Former Soviet Union region. (For a further discussion of some recent developments in this area, see the Special Topic entitled "The Caspian -- Will the Payoff be Worth the Risk?" in Chapter 4.) In Canada, several companies increased their oil production in 1998. Union Pacific Resources reported a substantial increase in oil production, in large part due to its acquisition of Norcen Energy Resources.[Note 59] Both Mobil and Chevron recorded large oil production increases from the Hibernia field offshore Newfoundland.[Note 60] Mobil just started producing there in 1997, and Chevron boosted production by drilling addition wells and utilizing water and gas injection methods in its operations. (For a further discussion of recent developments in Canada, see the Special Topic entitled "Canada -- A New Era for Exploration and Development" in

Chapter 4.) In the Middle East, Occidental Petroleum has been increasing its production in Qatar for several years, and, in 1998, it acquired production interests in Yemen from the Royal Dutch/Shell Group in an asset swap.[Note 61] Also, Texaco reported increased production in the Partitioned Neutral Zone in 1998.[Note 62]

Natural gas production for the FRS companies also grew in all regions except Asia Pacific (Table 14).[Note 63] The leading growth regions were Canada, OECD Europe, and the Other Western Hemisphere (mostly Latin America). Again, largely because of the acquisition of Norcen Energy Resources by Union Pacific Resources, Union Pacific's production of gas in Canada grew from 6 billion cubic feet in 1997 to 103 billion cubic feet in 1998. Similarly, USX's acquisition of Tarragon Oil and Gas was the primary source of the company's Canadian production increase, from none in 1997 to 24 billion cubic feet in 1998.[Note 64] In Europe, Exxon was one of the leading gainers, with gas production increasing by 34 billion cubic feet.[Note 65] Exxon has major gas-producing operations in the Netherlands, the United Kingdom, Germany, and Norway, resulting in Western Europe accounting for 48 percent of Exxon's 1998 worldwide gas production.[Note 66] Texaco was one of the other FRS companies with substantial increases in gas production in Europe, particularly in the United Kingdom.[Note 67] (For a further discussion of recent developments in the North Sea, see the Special Topic entitled "The North Sea - Development Outpaces Exploration" in Chapter 4.)

# U.S. Refining and Marketing

### U.S. Refining/Marketing Operations Excel Despite Low Oil Prices 1998

The FRS companies' U.S. refining/marketing operations were more profitable during 1998 than for any year since 1989, with their return on investment [Note 68] reaching 8 percent (Figure 14). Net income of the incumbent FRS companies (see the box entitled "Why Incumbents and Entrants?") increased 43 percent during 1998 relative to 1997, as reduced revenues were more than offset by reductions in operating costs (Table 15). Refined product revenues of the incumbent FRS companies fell $41.8 billion while operating costs fell $42.3 billion, resulting in a $0.5-billion increase in operating income and an increase of $1.7 billion in net income (excluding unusual items). Many developments during 1998 most likely would have reduced the profitability of U.S. refining and marketing operations, but in most cases the incumbent FRS companies maintained their profitability, usually through actions initiated long before 1998.

Changes in refining/marketing return on investment can be affected by activities that are tangential to the production and sale of refined petroleum products (e.g., non-fuel sales through retail outlets). Consequently, a financial measure that is closely tied to the production and sale of refined petroleum products provides a clearer explanation of the underlying causes of the profitability of refining/marketing. The net refined product margin (net margin) is such a measure. It not only reflects before-tax cash earnings from the production and sale of refined petroleum products, it also is strongly correlated with refining/marketing return on investment. [Note 69],[Note 70] The net margin is the gross margin (refined product revenues minus purchases of raw materials input to refining and refined product purchases) minus out-of-pocket operating costs per barrel of refined product sold. During 1998 the net margin for the FRS companies increased for the third consecutive year (Figure 15), rising 6 cents per barrel for the incumbent FRS companies (Table 16). The net margin increased during 1998 largely because out-of-pocket costs fell 41 cents per barrel as decade-long cost-cutting efforts by incumbent FRS companies continued to bear fruit. The balance of this section will review changes in the net margin and its components--specifically, product revenues, the gross margin, and operating costs directly related to producing and selling refined products.

### Low Product Prices and Declines in Sales Depress Product Revenues

Although profitability reached a decade-high 8 percent during 1998, product revenues were 33 percent lower for the incumbent FRS firms (Table 15).[Note 71] Product revenues fell during 1998, in part a reflection of the $6.25 fall in the average price per barrel of petroleum product that the companies sold (Table 17). The main cause of lower product prices was the $5.89-per-barrel decline in raw material input prices (mainly crude oil). A variety of other developments in 1998 had a mixture of effects on petroleum prices. Gross domestic product grew by 4 percent during 1998[Note 72] and consumption of petroleum products grew by nearly 2 percent,[Note 73] putting upward pressure on petroleum product prices. A 42-percent increase in electric utilities' consumption of heavy fuel oil for electricity generation[Note 74] also put upward pressure on product prices. However, petroleum product stocks increased during 1998,[Note 75] as they did in 1997, putting downward pressure on prices. Additionally, the unusually warm winter of 1998[Note 76] reduced the consumption of heating fuels, adding to product stocks and further depressing product prices. Also adding to the downward effect on prices was a 20-fold increase in jet fuel imports to U.S. West Coast markets (PADD 5).[Note 77] (See the Highlight entitled "Are Downstream Investments More Profitable in California Than the Rest of the Country?" for a broader discussion of recent PADD 5 refining/marketing developments.) Thus, the growth in domestic consumption of petroleum products was more than offset by the growth in product supply.[Note 78]

Not only did product prices received by incumbent FRS firms fall during 1998, but product sales volume also declined (Table 17). Sales were lower because the incumbent FRS firms continued to refocus and consolidate their retailing operations during 1998[Note 79] (Table 18). However, the lower sales are also partly a reflection of the reorganization of both Shell Oil and Texaco, whose 1998 sales were reported by Equilon Enterprises and Motiva Enterprises, entrant FRS firms.

Part of the reason for the decline in product sales was the decline in the refining capacity of the incumbent FRS firms (Table 19). Some refining capacity was sold[Note 80] and some capacity was transferred to joint ventures.[Note 81] Further, the utilization rate of the remaining refinery capacity fell during 1998 because of shutdowns for fall storms.[Note 82]

### Gross Margins Squeezed in 1998

The downward pressure that growing petroleum product stocks exerted on product prices had effects on the gross margin. If crude oil prices are falling and the gross margin is declining, then petroleum product prices are generally falling at a greater rate than are crude oil prices.[Note 83]

Gross margins varied considerably over the course of the year. Industry-wide gross margins during the first quarter of 1998 were 20 cents per barrel higher than during the first quarter of 1997[Note 84] despite the warmer-than-usual winter. However, by the end of the second quarter, gross margins had fallen substantially, and were 43 cents per barrel lower than a year earlier. By the third quarter this decline had considerably worsened, as margins were $1.08 per barrel lower than during the third quarter of 1997. The year closed with fourth-quarter gross margins 29 cents lower than at the close of 1997.

For the FRS incumbent companies, the gross margin in 1998 was 36 cents per barrel lower than in 1997 (Table 17). Although the price of crude oil and other raw materials fell $5.89 (as growing crude oil stocks provided downward pressure on prices[Note 85]), the incumbent FRS companies' refined product prices fell by $6.25 per barrel.

### Reduced Costs More Than Offset Lower Gross Margin

The key to heightened refining/marketing profitability in 1998 was reduced operating costs. Reductions in out-of-pocket expenses were greater than the decrease in the gross margin, increasing the net refined product margin to its highest level of this decade (Figure 15).[Note 86] Out-of-pocket expenses were lower during 1998 because energy costs of incumbent FRS companies fell 28 cents per barrel, mainly because of lower oil and gas prices, but also through strategic actions such as building and operating cogeneration plants.[Note 87] Marketing costs fell as the incumbent FRS firms continued to consolidate their marketing operations during 1998 (Table 18).[Note 88] Company-operated outlets of incumbent FRS firms were reduced by 12 percent during 1998, falling by more than 1,000 outlets (Table 18 and Figure 16). Additionally, the incumbent FRS firms achieved more benefit from their remaining gasoline outlets. Thus, marketing costs were diminished further as the average sales volumes of remaining branded retail outlets increased 3,500 gallons per month (a 4-percent increase) through dealer outlets and by almost 11 thousand gallons per month (an 8-percent increase) through company-operated outlets.

Thus, reductions in out-of-pocket costs led to a 6-cents-per-barrel-of-product-sold increase in the net margin, which yielded an increase in the profitability of the domestic refining and marketing operations of the incumbent FRS companies. Consequently, despite significant reductions in product prices and sales volumes, the domestic refining and marketing operations of the incumbent FRS companies not only survived 1998, but their net margin from these operations increased by 4 percent (Table 17), a result achieved through cost-cutting efforts not only in 1998 but throughout this decade.

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## *Highlight -- Are Downstream Investments More Profitable in California Than the Rest of the Country?*

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California's motor gasoline prices tend to be higher than average U.S. retail prices. This pattern prevails despite California having 23 refineries with total capacity of almost 2 million barrels[a] of crude oil per day[b] and more than 11 thousand retail outlets from which motor gasoline may be purchased.[c] Allegations are made periodically that the profitability of motor gasoline sales by major refiners in California is excessive.

California is one of seven states comprising Petroleum Administration for Defense District Five (PADD 5).[d] This review of the characteristics of the downstream petroleum (crude oil refining and motor gasoline marketing) industry in PADD 5 relative to the other regions will provide background information against which one may examine the major refiners' profitability in PADD 5 and, by implication, their profitability in California.[e]

Several statistics for PADD 5 are of note. PADD 5 retail outlets sold the highest volume per station in the country, averaging 101 thousand gallons monthly per outlet during 1998 (compared to 57 thousand gallons per month for the rest of the United States). Thus, retail outlets in PADD 5 appeared to be operated more intensively than retail outlets elsewhere in the country (Table 20). However, outlets per capita averaged only one per 2,600 persons in PADD 5 compared with one outlet per 1,400 persons elsewhere in the United States.

Critics of PADD 5 refiners may point to the relatively small number of retail operations per capita (about 60 percent of the national average) in PADD 5 as evidence of relatively less competition in the industry (and an implication of excessive profitability). Alternatively, defenders of the industry may point to the high sales volume per outlet as an indication of competition in the industry (and an implication of normal profitability). Fortunately, the availability of widely accepted measures of profitability (and data to estimate them) facilitates a more systematic examination of PADD 5 profitability.

One way to examine profitability is to compare the rates of return of PADD 5 refiners with those of other U.S. refiners. The FRS database lends itself well, but imperfectly, to such a comparison. The FRS companies can be divided into two groups of refiners: those that are primarily based in PADD 5 and those that are primarily based outside of PADD 5.[f] The PADD 5 group consists of 6 companies that overall have 60 percent of their domestic refining capacity located in PADD 5 (mostly in California).[g] The other U.S. group consists of 12 companies, which have 4 percent of their total domestic refining capacity in PADD 5.[h]

Profitability of FRS lines of business is usually measured by return on investment.[i] Between 1989 and 1998 the return on investment, on average, was approximately the same for PADD 5 refiners as it was for other U.S. refiners, 4.2 percent and 4.9 percent, respectively (Figure 17).[j] Admittedly, annual returns of both groups varied considerably between 1989 and 1998 and demonstrated somewhat different patterns of variation. This comparison indicates that PADD 5 refiners achieved a level of profitability similar to non-PADD 5 refiners between 1989 and 1998.

However, consumers may tend to pay more attention to gasoline prices at the pump than to oil company rates of return. Figure 18 shows that average gasoline prices for FRS refiners (which exclude taxes) in PADD 5 have been higher than the rest of the country beginning in 1993.[k]

How is it that PADD 5 refiners are no more profitable on average than other refiners yet realize higher prices for gasoline? To answer this question, we begin by examining the gross margin. The gross margin is the difference between the average petroleum product price received and the cost of raw materials (chiefly crude oil). PADD 5 refiners report higher gross margins than do other U.S. refiners (Figure 19).[l] However, raw materials costs, including any product purchases for resale or rerun, are little different between the two groups.

Based on FRS data, the answer to the question is found in operating costs. Between 1989 and 1998 FRS company operating costs were substantially higher for PADD 5 refiners than for other U.S. refiners. PADD 5 refiners' operating costs averaged $6.98 per barrel compared to other U.S. refiners' average of $5.01 per barrel over the past 10 years.[m] Notably, the difference widened in 1996, as California's reformulated motor gasoline requirement became effective January 1, 1996 (Figure 20).[n] Thus, higher gross margins received by FRS refiners in PADD 5 than by other U.S. refiners may simply have been driven by higher operating costs.

Part of the difference in operating costs may reflect the relatively higher environmental requirements imposed by the California Air Resources Board on motor gasoline sold in California, which constituted 66 percent[o] of motor gasoline sold in PADD 5 during 1998.[p] Similarly, California has higher environmental restrictions on diesel fuel than does the United States. The stricter California environmental regulations may have contributed to slightly higher diesel fuel prices received by PADD 5 refiners than received by other U.S. refiners ($24.31 per barrel and $23.48 per barrel, respectively, between 1996 and 1998 (in 1998 dollars)).[q]

Consequently, comparisons of returns on investment, gross refining margins, and average prices of PADD 5 refiners with those of other U.S. refiners provide little evidence to support of the contention that PADD 5 refiners have higher profitability than do other U.S. refiners. Thus, higher California motor gasoline and diesel prices may simply reflect the higher costs of supplying consumers, instead of the exercise of market power to extract higher profits from consumers.

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a A barrel of petroleum contains 42 gallons.
b Energy Information Administration, *Petroleum Supply Annual 1998*, Volume 1, DOE/EIA-0340(98)/1 (Washington, DC, June 1999), Table 36.
c *National Petroleum News Market Facts 1999* (mid-July 1999), p. 124.
d Energy Information Administration, *Petroleum Supply Annual 1998*, Volume 1, DOE/EIA-0340(98)/1 (Washington, DC, June 1999), p. 125. During World War II, the Federal government created domestic geographic districts in order to administer oil allocation; these geographical districts are still used today by the Energy Information Administration (EIA) as a way to categorize regional energy supply statistics. The continued use of these regions permits EIA to provide sub-national petroleum supply statistics without the expense of collecting state-level data.
e Although much state-level information exists, energy financial information is rarely available on such a disaggregated level, hence the focus on PADD 5 instead of California.
f Because Texaco and Shell formed the joint venture Equilon that included the PADD 5 refineries of both companies, Equilon is included with the PADD 5 refineries for the year 1998, its first year as an FRS respondent. Similarly, although Tosco owns refineries nationwide, the majority of its refining capacity was acquired from Unocal when Unocal exited downstream petroleum operations at the end of 1996. Thus, Tosco also is included with the PADD 5 refineries for 1998, the first year that Tosco was an FRS respondent.
g The PADD 5 group consists of ARCO, Chevron, Equilon (which replaced Texaco in 1998), Texaco, Tosco (which replaced Unocal in 1998), and Unocal. These companies have a total of 1,959.6 thousand barrels of their domestic capacity of 3,281.95 thousand barrels located in PADD 5. See Energy Information Administration, *Petroleum Supply Annual 1998*, Volume 1, DOE/EIA-0340(98)/1 (Washington, DC, June 1999), Table 40.
h The group of other U.S. refiners consists of Amoco, Ashland, BP America, Coastal, Conoco/duPont, Exxon, Fina, Marathon/USX, Mobil, Phillips, Shell Oil, and Sunoco. These companies have a total of 259.5 thousand barrels of their total domestic refining capacity of 7,232.5 thousand barrels located in PADD5. See Energy Information Administration, *Petroleum Supply Annual 1998*, Volume 1, DOE/EIA-0340(98)/1 (Washington, DC, June 1999), Table 40.
i Return on investment is net income divided by net investment in place.

j The computed t-statistic is 1.2, which is less than the critical value of 2.1 for a 5-percent level of confidence (two-tailed test) and 18 degrees of freedom. The 0.7-percent difference between the 10-year means of 4.9 percent and 4.2 percent is not significantly different from zero. See, for example, Collin Watson, Patrick Billingsley, D. James Croft, and David Huntsberger, *Statistics for Management and Economics*, 4th edition (Allyn and Bacon: Boston, Massachusetts, 1990), pp. 393-395.

k The computed t-statistic is 2.1, which is more than the critical value of 1.8 for a 10-percent level of confidence (two-tailed test) and 10 degrees of freedom. See, for example, Collin Watson, Patrick Billingsley, D. James Croft, and David Huntsberger, *Statistics for Management and Economics*, 4th edition (Allyn and Bacon: Boston, Massachusetts, 1990), pp. 393-395.

l The gross margin for PADD 5 refiners averaged $8.76 per barrel ($1998) between 1989 and 1998. The gross margin of other U.S. refiners averaged $6.81 per barrel over the same period.

m The computed t-statistic is 5.7, which is more than the critical value of 1.7 for a 10-percent degree of confidence (two-tailed test) and 18 degrees of freedom. See, for example, Collin Watson, Patrick Billingsley, D. James Croft, and David Huntsberger, *Statistics for Management and Economics*, 4th edition (Allyn and Bacon: Boston, Massachusetts, 1990), pp. 393-395.

n See the California Air Resources Board (CARB) website for a discussion of the environmental requirements of California and CARB.

o During 1998 an estimated 32,087,200 thousand gallons per day of motor gasoline were sold in California compared to an estimated 48,258,800 thousand gallons per day sold in all of PADD 5. See Energy Information Administration, *Petroleum Marketing Annual 1998*, DOE/EIA-0487(98) (Washington, DC, October 1999), Table 43.

p See the CARB website for a discussion of the relatively higher restrictions of California and CARB compared to the rest of the United States. The Clean Air Act and its associated amendments can be found on CARB's website at http://www.arb.ca.gov/html/fcaa.htm and on the Environmental Protection Agency's website http://www.epa.gov/epahome/laws.htm.

q However, the difference between the average prices is not significantly different from zero. The computed t-statistic is 0.7, which is less than the critical value of 2.1 for a 10-percent degree of confidence (two-tailed test) and 4 degrees of freedom. See, for example, Collin Watson, Patrick Billingsley, D. James Croft, and David Huntsberger, *Statistics for Management and Economics*, 4th edition (Allyn and Bacon: Boston, Massachusetts, 1990), pp. 393-395.

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# Chapter 3 Endnotes

55. The entering FRS companies produced no oil in 1998.
56. Atlantic Richfield, *1998 Annual Report*, p. 17.
57. Shell Oil, *1998 Securities and Exchange Commission Report 10-K*, p. 4.
58. Accounting rules of the American Institute of CPAs specify that production from these joint ventures no longer be included in Shell's consolidated production.
59. Union Pacific Resources Group, *1998 Annual Report*, p. 3 and *1998 Securities and Exchange Commission Report 10-K*, p. 72.
60. Mobil, *1998 Annual Report*, p. 16, and Chevron, *1998 Annual Report*, pp. 18-19.
61. Occidental Petroleum, *1998 Annual Report*, p. 3.

62. Texaco, *1998 Annual Report*, p. 27.

63. For the FRS incumbents only, gas production in the U.S. onshore also declined.

64. Marathon, *1998 Annual Report*, p. U-35.

65. Exxon, *1998 Annual Report* (October 27, 1999), pp. 26-30.

66. Exxon, *1998 Annual Report* (October 27, 1999), pp. 26-30.

67. Texaco, *1998 Financial and Operating Supplement*, pp. 13 and 22.

68. Return on investment is net income divided by net investment in place.

69. The net margin and return on investment have a correlation coefficient of 92 percent. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997).

70. The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.

71. Although incumbent FRS refiners were able to increase revenues from sources such as convenience store sales (i.e., "other" revenues), which somewhat offset the reduction in refined product revenues, this stream of revenue is unrelated to the production and sale of petroleum products and has no effect on the gross or net margins.

72. Energy Information Administration, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), Appendix E.

73. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999), Table 1.3.

74. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999), Table 7.3.

75. Between the end of 1996 and the end of 1998, motor gasoline stocks grew by 11 percent, distillate fuel stocks grew by 23 percent, residual fuel stocks grew by 5 percent (but by 11 percent since the end of 1997), and jet fuel stocks grew by 13 percent. See Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999), Tables 3.4, 3.5, 3.6, and 3.7, respectively.

76. Energy Information Administration, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), Table 1.7.

77. Jet fuel exports from Asia may have been triggered by lingering problems from the Asian financial crisis of 1997. The imports were almost exclusively from the Republic of Korea and Singapore. See Energy Information Administration, Office of Oil and Gas, EIA Form 814 (Monthly Imports Report).

78. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999), Tables 3.4, 3.5, 3.6, and 3.7.

79. Consolidation of retailing outlets continued through 1998. For example, see Coastal Corporation, *1998 Annual Report*, p. 27 and Conoco, *1998 Annual Report*, p. 32.

80. Usually the sale was to one of the entrant FRS companies. For example, Mobil sold its Paulsboro, New Jersey refinery to Valero. See Mobil Corporation, *Fact Book 1998*, p. 53.

81. The transfers tended to be associated with the entrant FRS firms. For example, Shell Oil and Texaco transferred much of their refining capacity to Equilon Enterprises or Motiva Enterprises, both entrant FRS firms.

82. Chevron Corporation, *1998 Annual Report*, p. 31.

83. Alternatively, if prices for both petroleum products and crude oil are increasing, then a declining gross margin would indictate that crude oil prices are rising at a greater rate than are petroleum product prices.

84. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September 1999), Table 3.2b and *Petroleum Marketing Monthly*, DOE/EIA-0380(99/09) (Washington, DC, September 1999), Tables 31, 36-39, 42-43, and 45-47.

85. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/09) (Washington, DC, September

1999), Table 3.1a.

86. The net margin is strongly related to profitability (measured by return on investment) as demonstrated by a correlation coefficient of 92. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997).
87. Utilizing cogeneration plants to power refineries and sell excess electricity is one way by which energy costs are lowered. For example, See Exxon Corporation, *1998 Annual Report*, p. 13 and "Sunoco Announces Agreement with FPL Energy on Cogeneration plant at Marcus Hook Refinery," PRNewswire (October 14, 1999)
88. Marketing costs have been reduced through continued consolidation of retailing outlets. For example, see Coastal Corporation, *1998 Annual Report*, p. 27 and Conoco, *1998 Annual Report*, p. 32.

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**Table 11.**
**Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1997-1998**

| Prices, Sales, and Production | 1997 | 1998 | Percent Change 1997-1998 |
|---|---|---|---|
| **Domestic Oil and Gas Production[a]** | | | |
| Crude Oil and NGL (Million Barrels) | 1,458.8 | 1,388.8 | -4.8 |
| Dry Natural Gas (Billion Cubic Feet) | 8,299.1 | 8,395.9 | 1.2 |
| Total (Million Barrels COE)[b] | 2,936.0 | 2,883.3 | -1.8 |
| Domestic Oil and Gas Sales Volumes | | | |
| Crude Oil and NGL (Million Barrels) | 1,860.4 | 1,805.3 | -3.0 |
| Dry Natural Gas (Billion Cubic Feet) | 12,420.7 | 11,764.6 | -5.3 |
| Total (Million Barrels COE)[b] | 4,071.3 | 3,899.4 | -4.2 |
| **Domestic Production Segment Per Unit Sales Values** | | | |
| Crude Oil and NGL (Dollars Per Barrel) | 16.45 | 10.91 | -33.7 |
| Dry Natural Gas (Dollars Per Thousand Cubic Feet) | 2.37 | 2.01 | -15.2 |
| Composite (Dollars Per Barrel COE)[b] | 14.75 | 11.11 | -24.7 |
| **Foreign Oil and Gas Production[a]** | | | |
| Crude Oil and NGL (Million Barrels) | 1,473.2 | 1,546.1 | 4.9 |
| Dry Natural Gas (Billion Cubic Feet) | 4,858.8 | 5,181.8 | 6.6 |
| Total (Million Barrels COE)[b] | 2,338.1 | 2,468.5 | 5.6 |
| **Foreign Production Segment Per Unit Sales Values** | | | |
| Crude Oil and NGL (Dollars Per Barrel) | 18.01 | 11.61 | -35.5 |
| Dry Natural Gas (Dollars Per Thousand Cubic Feet) | 2.22 | 2.08 | -6.3 |
| Canada | 1.54 | 1.35 | -12.3 |
| OECD Europe | 2.89 | 2.56 | -11.4 |
| Other Foreign | 1.88 | 1.90 | 1.1 |
| Composite (Dollars Per Barrel COE)[b] | 15.96 | 11.64 | -27.1 |

[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.

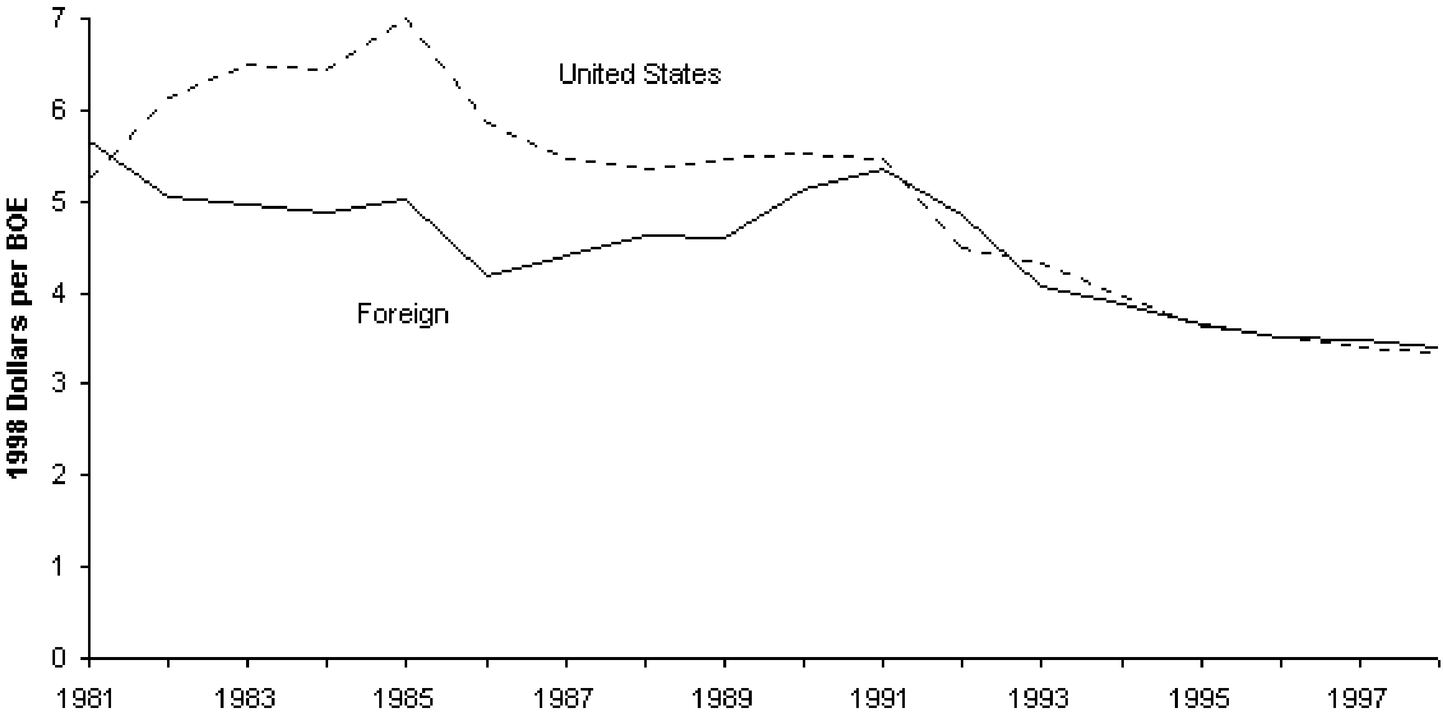
**Table 12. Income Components and Financial Ratios in Oil and Gas Production for FRS Companies, 1997-1998**
(Billion Dollars)

| Components of Income and Financial Ratios | United States | | Foreign | |
|---|---|---|---|---|
| | 1997 | 1998 | 1997 | 1998 |
| Oil and Gas Revenues | | | | |
| Oil | 30.6 | 19.7 | NA | NA |
| Gas | 29.5 | 23.6 | NA | NA |
| Total Revenues | 60.1 | 43.3 | 44.2 | 35.5 |
| Expenses | | | | |
| DD&A | 10.4 | 12.8 | 8.0 | 10.4 |
| Lifting Costs | 12.1 | 11.0 | 9.8 | 9.7 |
| Exploration Expenses | 2.1 | 1.9 | 3.6 | 2.6 |
| General and Administrative Expenses | 0.9 | 1.1 | 0.7 | 0.8 |
| Raw Material Purchases | 16.6 | 13.6 | 6.9 | 6.3 |
| Other Costs (Revenues) | 3.1 | 2.5 | -0.8 | 3.0 |
| Total Operating Expenses | 45.1 | 42.7 | 28.2 | 32.8 |
| Operating Income | 15.0 | 0.6 | 16.0 | 2.6 |
| Other Income (Expense)[a] | 1.9 | -0.4 | 2.4 | 1.9 |
| Income Tax Expense | 5.3 | -0.3 | 8.9 | 2.4 |
| Net Income | 11.6 | 0.5 | 9.6 | 2.0 |
| Less Unusual Items | 0.1 | -2.7 | 0.7 | -2.4 |
| Net Income, Excluding Unusual Items | 11.4 | 3.2 | 8.8 | 4.4 |
| Unit Values (Dollars Per Barrel of Production COE)[b] | | | | |
| Direct Lifting Costs (Excluding Taxes) | 3.46 | 3.39 | 3.36 | 3.36 |
| Production Taxes | 0.67 | 0.41 | 0.83 | 0.57 |
| Ratios (Percent) | | | | |
| Return on Investment[c] | 12.5 | 0.5 | 12.5 | 2.2 |
| Effective Tax Rate[d] | 31.7 | -- | 48.4 | 54.6 |

[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.
DD&A = Depreciation, depletion, and amortization costs.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/15/99*

**Figure 13. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-1998**




BOE = Barrels of crude oil equivalent.

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

## Table 13.
## Lifting Costs by Region for FRS Companies, 1997-1998
(Dollars Per Barrel of Oil Equivalent)

| Region | Direct Lifting Costs | | | Production Taxes | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1997 | 1998 | Percent Change | 1997 | 1998 | Percent Change | 1997 | 1998 | Percent Change |
| United States | | | | | | | | | |
| Onshore | -- | -- | -- | -- | -- | -- | 4.57 | 4.60 | 0.7 |
| Offshore | -- | -- | -- | -- | -- | -- | 2.95 | 2.88 | -2.4 |
| Total United States | 3.46 | 3.39 | -1.8 | 0.67 | 0.41 | -39.1 | 4.13 | 3.80 | -7.8 |
| Foreign | | | | | | | | | |
| Canada | 3.55 | 3.17 | -10.8 | 0.33 | 0.28 | -13.5 | 3.88 | 3.45 | -11.0 |
| OECD Europe | 4.35 | 4.28 | -1.6 | 0.64 | 0.56 | -12.0 | 4.99 | 4.84 | -2.9 |
| Former Soviet Union and Eastern Europe | W | 8.41 | W | W | 0.04 | W | W | 8.45 | W |
| Africa | 2.76 | 3.66 | 32.6 | 1.44 | 0.91 | -37.0 | 4.20 | 4.56 | 8.7 |
| Middle East | 2.23 | 1.70 | -23.9 | 1.68 | 1.21 | -27.6 | 3.90 | 2.91 | -25.5 |
| Other Eastern Hemisphere | 2.01 | 1.94 | -3.4 | 0.80 | 0.43 | -45.9 | 2.81 | 2.37 | -15.5 |
| Other Western Hemisphere | 3.31 | 3.48 | 5.0 | 1.10 | 0.55 | -50.1 | 4.41 | 4.03 | -8.7 |
| Total Foreign | 3.36 | 3.36 | 0.0 | 0.83 | 0.57 | -31.0 | 4.19 | 3.93 | -6.1 |
| Worldwide Total | 3.41 | 3.38 | -1.0 | 0.74 | 0.48 | -34.6 | 4.15 | 3.86 | -7.0 |

-- = Data not available.
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).

*Last Updated on 12/9/99*

## Table 14.
## Production of Oil and Natural Gas by Region for FRS Companies, 1997-1998

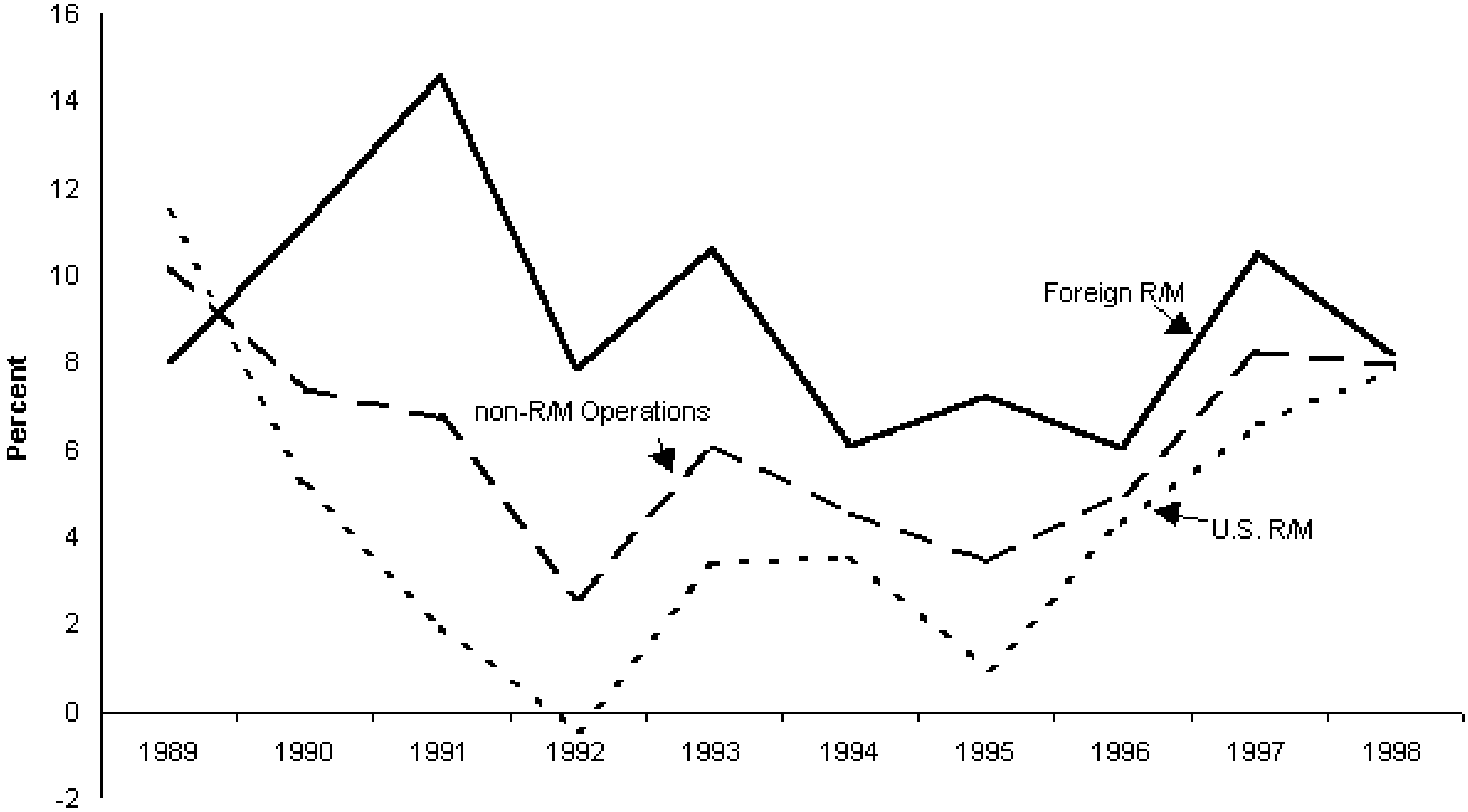
| Region | Oil (million barrels) | | | Natural Gas (billion cubic feet) | | |
|---|---|---|---|---|---|---|
| | **1997** | **1998** | **Percent Change** | **1997** | **1998** | **Percent Change** |
| United States | | | | | | |
| Onshore | 1,096 | 991 | -9.5 | 5,450 | 5,493 | 0.8 |
| Offshore | 363 | 397 | 9.5 | 2,849 | 2,903 | 1.9 |
| Total United States | 1,459 | 1,389 | -4.8 | 8,299 | 8,396 | 1.2 |
| Foreign | | | | | | |
| Canada | 139 | 173 | 24.5 | 741 | 869 | 17.2 |
| Europe and Former Soviet Union | 564 | 582 | 3.1 | 1,984 | 2,093 | 5.5 |
| Africa | 309 | 320 | 3.6 | 17 | 34 | 102.7 |
| Middle East | 109 | 130 | 19.0 | 91 | 97 | 5.6 |
| Other Eastern Hemisphere | 266 | 251 | -5.4 | 1,711 | 1,702 | -0.5 |
| Other Western Hemisphere | 86 | 90 | 4.6 | 315 | 387 | 23.0 |
| Total Foreign | 1,473 | 1,546 | 4.9 | 4,859 | 5,182 | 6.6 |
| Worldwide Total | 2,932 | 2,935 | 0.1 | 13,158 | 13,578 | 3.2 |

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

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

*Last Updated on 12/9/99*

**Figure 14. Return on Investment in Refining/Marketing for FRS Companies, 1989-1998**




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

**Table 15.**
**Domestic Refining/Marketing Financial Items for FRS Companies, 1997-1998**
(Million Dollars)

| | 1997 | 1998 | | | Percent Change 1997-1998 | |
|---|---|---|---|---|---|---|
| | | All FRS Companies | Incumbent [a] FRS Companies | Entrant FRS Companies | All FRS Companies | Incumbent [a] FRS Companies |
| Refined Product Revenues | 129,111 | 147,456 | 86,095 | 61,361 | 14.2 | -33.3 |
| plus Other Revenues [b] | 10,430 | 17,073 | 11,649 | 5,424 | 63.7 | 11.7 |
| minus Total Operating Expenses [b, c] | 134,793 | 157,780 | 92,489 | 65,291 | 17.1 | -31.4 |
| equals Operating Income [c] | 4,748 | 6,749 | 5,255 | 1,494 | 42.1 | 10.7 |
| Net Income, excluding unusual items | 3,285 | 6,943 | 4,936 | 2,007 | 111.4 | 50.3 |
| minus Unusual Items | 179 | 1,039 | 487 | 552 | (d) | (d) |
| equals Net Income | 3,106 | 5,904 | 4,449 | 1,455 | 90.1 | 43.2 |

[a] Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

[b] Raw material revenues are netted against total operating expense (see Table B32).

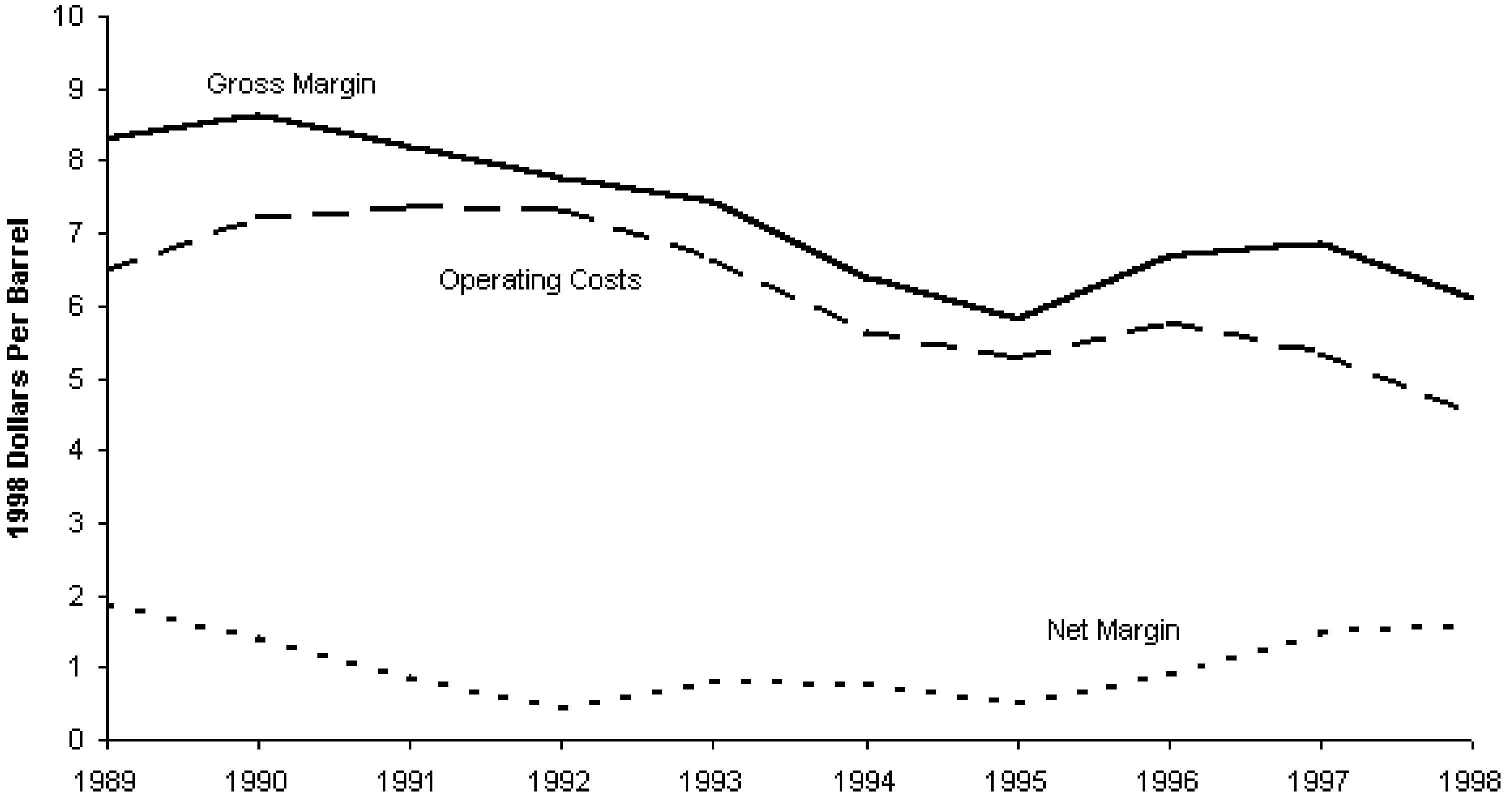
[c] Excludes unusual items.

[d] Percent change not calculated because unusual items are non-recurring.

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

*Last Updated on 12/9/99*

**Figure 15. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1989-1998**




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

**Table 16.**
**U.S. Refined Product Margins and Costs per Barrel Sold for FRS Companies, 1994-1998**
(1998 Dollars per Barrel)

| | 1994 | 1995 | 1996 | 1997 | 1998 All FRS Companies | 1998 Incumbent[a] FRS Companies | 1998 Entrant FRS Companies |
|---|---|---|---|---|---|---|---|
| Gross Margin[b] | 6.40 | 5.80 | 6.68 | 6.85 | 6.10 | 6.42 | 5.67 |
| less | | | | | | | |
| Marketing Costs | 1.93 | 1.83 | 1.87 | 1.78 | 1.41 | 1.68 | 1.04 |
| Energy Costs | 1.03 | 0.86 | 1.10 | 1.04 | 0.73 | 0.75 | 0.70 |
| Other Operating Expense | 2.68 | 2.59 | 2.81 | 2.54 | 2.39 | 2.47 | 2.28 |
| equals | | | | | | | |
| FRS Refined Product Margin[c] | 0.77 | 0.51 | 0.90 | 1.49 | 1.58 | 1.53 | 1.65 |
| Refined Product Sales Volume (Mb/d)[d] | 13,455 | 13,641 | 14,024 | 13,294 | 20,061 | 11,587 | 8,475 |

[a]Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

[b]Refined product revenues less raw material and product purchases divided by refined product sales volume.

[c]Calculated from unrounded data.

[d]Sales volumes include direct retail sales (through company-operated outlets, and open lessee dealer outlets); direct sales to industrial, commercial, and other retail customers; sales to other corporate business segments; and wholesale sales. Sales also include sales to other refiners. Consequently, some barrels of refined products are counted more than once in total FRS refined products sales volume.

Mb/d = Thousand barrels per day.

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

*Last Updated on 12/13/99*

## Table 17.
## Sales, Prices, and Margins in U.S. Refining/Marketing for FRS Companies, 1997-1998

| Sales, Expenses, and Income | 1997 | 1998 All FRS Companies | 1998 Incumbent [a] FRS Companies | 1998 Entrant FRS Companies | Percent Change 1997-1998 All FRS Companies | Percent Change 1997-1998 Incumbent [a] FRS Companies |
|---|---|---|---|---|---|---|
| | (million barrels per day) | | | | - | |
| Refined Product Sales | 13.29 | 20.06 | 11.59 | 8.47 | 50.9 | -12.8 |
| Average Sales Price | (dollars per barrel) | | | | - | - |
| Gasoline | 30.02 | 22.36 | 22.87 | 21.73 | -25.5 | -23.8 |
| Distillate | 25.10 | 18.21 | 18.45 | 17.85 | -27.4 | -26.5 |
| Other | 20.79 | 16.95 | 16.86 | 17.09 | -18.5 | -18.9 |
| All Refined Products | 26.61 | 20.14 | 20.36 | 19.84 | -24.3 | -23.5 |
| Raw Material Input and Product Purchases per Barrel | 19.83 | 14.03 | 13.94 | 14.17 | -29.2 | -29.7 |
| Average Sales Price Less Cost of Raw Materials and Product Purchases (Gross Margin) | 6.78 | 6.10 | 6.42 | 5.67 | -10.0 | -5.3 |
| Direct Operating Costs | 5.31 | 4.52 | 4.89 | 4.02 | -14.8 | -7.8 |
| Refined Product Margin[b] | 1.47 | 1.58 | 1.53 | 1.65 | 7.2 | 3.7 |
| Gasoline Marketing Margins | | | | | | |
| Wholesaler/Reseller | 5.65 | 5.71 | 4.98 | 6.93 | 1.2 | -11.8 |
| Retailer | 1.99 | 1.76 | 3.24 | -0.60 | -11.9 | 62.7 |

[a]Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

[b]See Appendix B, Table B32, 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).

*Last Updated on 12/9/99*

## Table 18.
## Gasoline Distribution by FRS Companies, 1997-1998

| Distribution Category | 1997 | 1998 | | | Percent Change 1997-1998 | |
|---|---|---|---|---|---|---|
| | | All FRS Companies | Incumbent[a] FRS Companies | Entrant FRS Companies | All FRS Companies | Incumbent[a] FRS Companies |
| Sales Volume | (million barrels) | | | | | |
| Wholesale Volume | 1,150 | 2,134 | 1,061 | 1,073 | 85.5 | -7.7 |
| Retail Volume | | | | | | |
| Dealer Volume | 615 | 752 | 516 | 236 | 22.4 | -16.0 |
| Company-Operated Volume | 335 | 558 | 320 | 238 | 66.4 | -4.5 |
| Direct Volume | 253 | 295 | 203 | 92 | 16.7 | -19.7 |
| Intersegment Volume | 18 | 70 | 18 | 52 | 285.5 | 1.1 |
| Total Volume | 1,421 | 2,499 | 1,283 | 1,216 | 75.8 | -9.8 |
| Outlets | (number of outlets) | | | | | |
| Dealer Outlets | 24,833 | 35,102 | 20,070 | 15,032 | 41.4 | -19.2 |
| Company-Operated Outlets | 8,920 | 13,645 | 7,873 | 5,772 | 53.0 | -11.7 |
| Total Retail Outlets | 33,753 | 48,747 | 27,943 | 20,804 | 44.4 | -17.2 |
| Average Monthly Outlet Volume | (thousand gallons per month) | | | | | |
| Dealers | 86.6 | 75.0 | 90.1 | 55.0 | -13.4 | 3.9 |
| Company Operated | 131.5 | 143.0 | 142.3 | 144.0 | 8.8 | 8.2 |
| All Retail | 98.5 | 94.1 | 104.8 | 79.7 | -4.5 | 6.4 |

[a] Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

Note: Percent changes were calculated from unrounded data.

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

*Last Updated on 12/9/99*

## Table 19.
## Refining Financial and Operating Data for FRS Companies, 1997-1998

| | 1997 | 1998 | | | Percent Change 1997-1998 | |
|---|---|---|---|---|---|---|
| | | All FRS Companies | Incumbent[a] FRS Companies | Entrant FRS Companies | All FRS Companies | Incumbent[a] FRS Companies |
| Refining Capital Intensity[b] | (thousands of dollars per barrel of daily capacity) | | | | | |
| United States | 2,673 | 2,539 | 2,269 | 3,059 | -5.0 | -15.1 |
| Refining Capacity | (thousand barrels per day) | | | | | |
| United States | 9,410 | 14,277 | 7,619 | 6,658 | 51.7 | -19.0 |
| Foreign | 4,270 | 4,508 | 4,348 | 160 | 5.6 | 1.8 |
| Total | 13,680 | 18,785 | 11,967 | 6,818 | 37.3 | -12.5 |
| Refinery Utilization Rate | (percent) | | | | | |
| United States | 94.8 | 93.0 | 92.2 | 94.1 | -- | -- |
| Foreign | 91.9 | 90.5 | 90.2 | 96.9 | -- | -- |

[a] FRS incumbent companies were respondents to Form EIA-28 in both 1997 and 1998.

[b]Refining capacity intensity is the year-end book value of corporate refining assets divided by average daily crude oil distillation capacity.

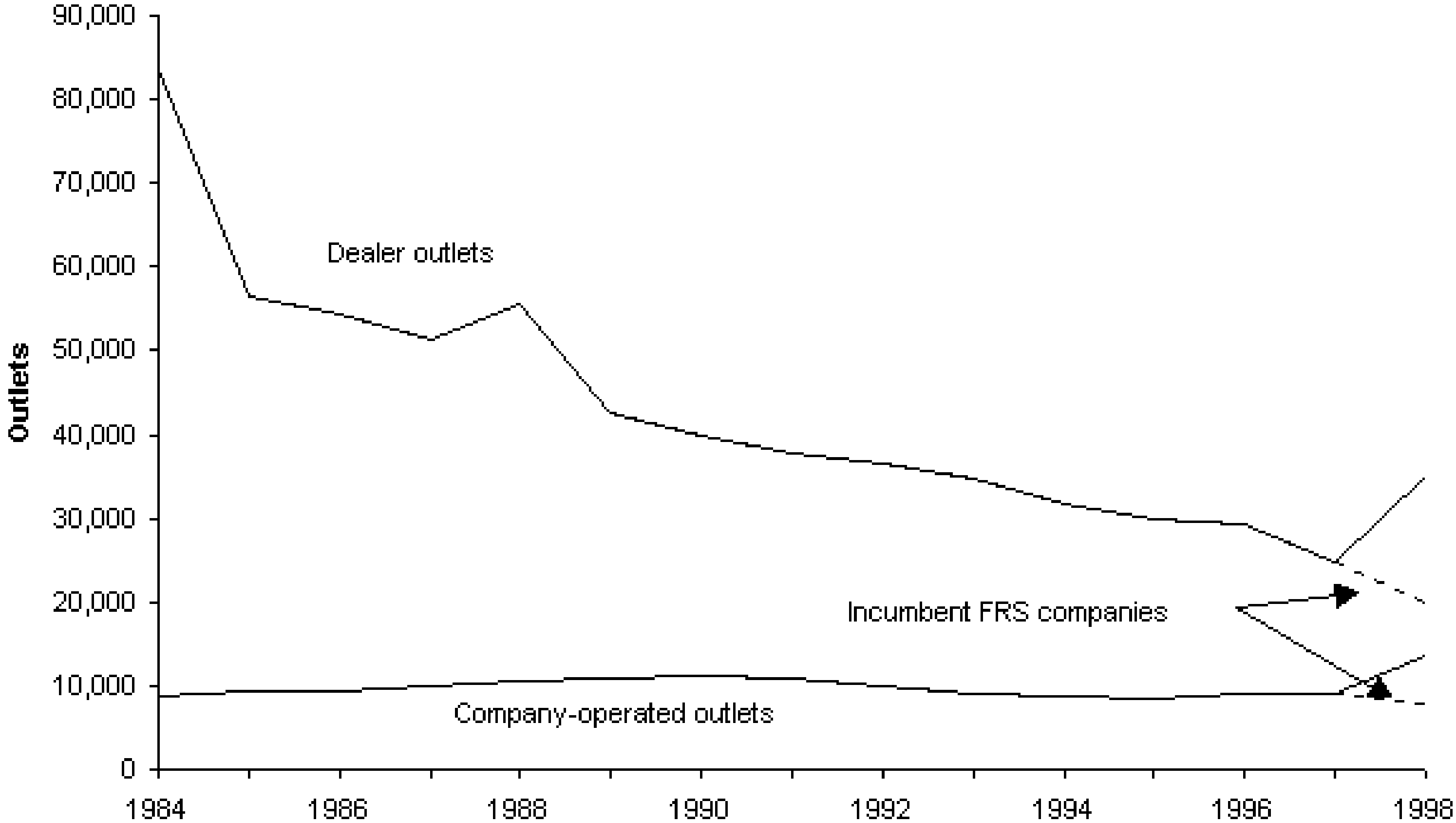
-- = Not meaningful.

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).

*Last Updated on 12/9/99*

Figure 16. Motor Gasoline Retail Outlets for FRS Companies, 1984-1998




Note: Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

**Table 20.**
**Selected Downstream Petroleum Characteristics, by Petroleum Administration for Defense District (PADD), 1998**

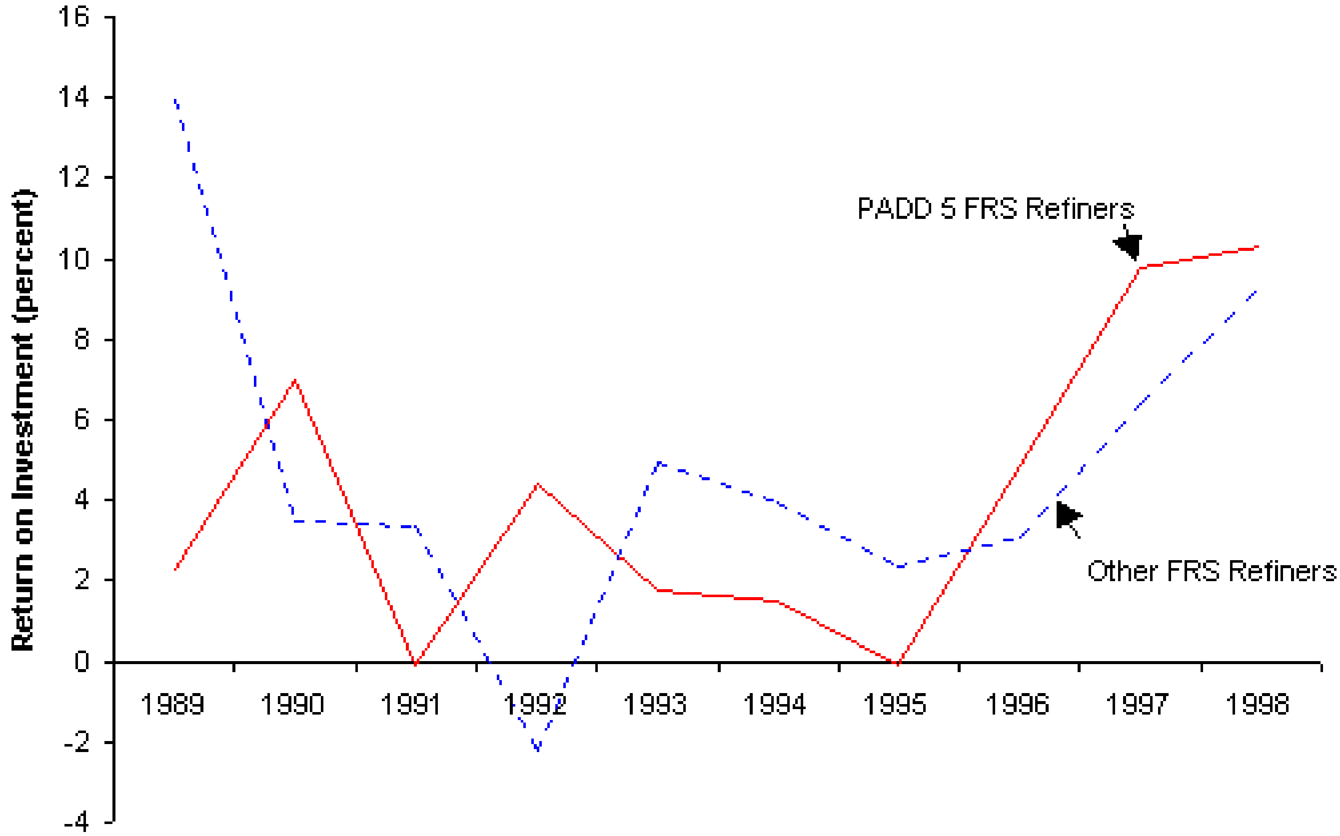
| | **Population** | **Number of Operating Refineries** | **Refinery Operating Crude Oil Distillation Capacity** (Barrels per day) | **Motor Gasoline Retail Outlets** | **Motor Gasoline Sold** (Thousands of Gallons) | **Motor Gasoline Sales Volume per Retail Outlet** (Thousands of Gallons per month) |
|---|---|---|---|---|---|---|
| **PADD 5** | 48,113,429 | 40 | 2,989,755 | 18,697 | 22,581,346 | 101 |
| **Other U.S.** | 222,185,095 | 115 | 13,071,735 | 161,870 | 110,186,747 | 57 |
| **U.S. Total** | 270,298,524 | 155 | 16,061,490 | 180,567 | 132,768,093 | 61 |

Note: PADD 5 consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

Sources: **Population**: U.S. Department of Commerce, Bureau of the Census, http://www.census.gov/population/estimates/state/st-98-3.txt (October 19, 1999); **Number and Capacity of Operating Refineries**: Energy Information Administration, *Petroleum Supply Annual 1998*, Volume 1 ( Washington, DC, June 1999), Table 35; **Motor Gasoline Outlets**: *National Petroleum News*, *Market Facts 1999*, Volume 91, Number 8 (July 1999), p. 116; **Motor Gasoline Sold**: Energy Information Administration, *Petroleum Marketing Annual 1998* ( Washington, DC), Table 43.

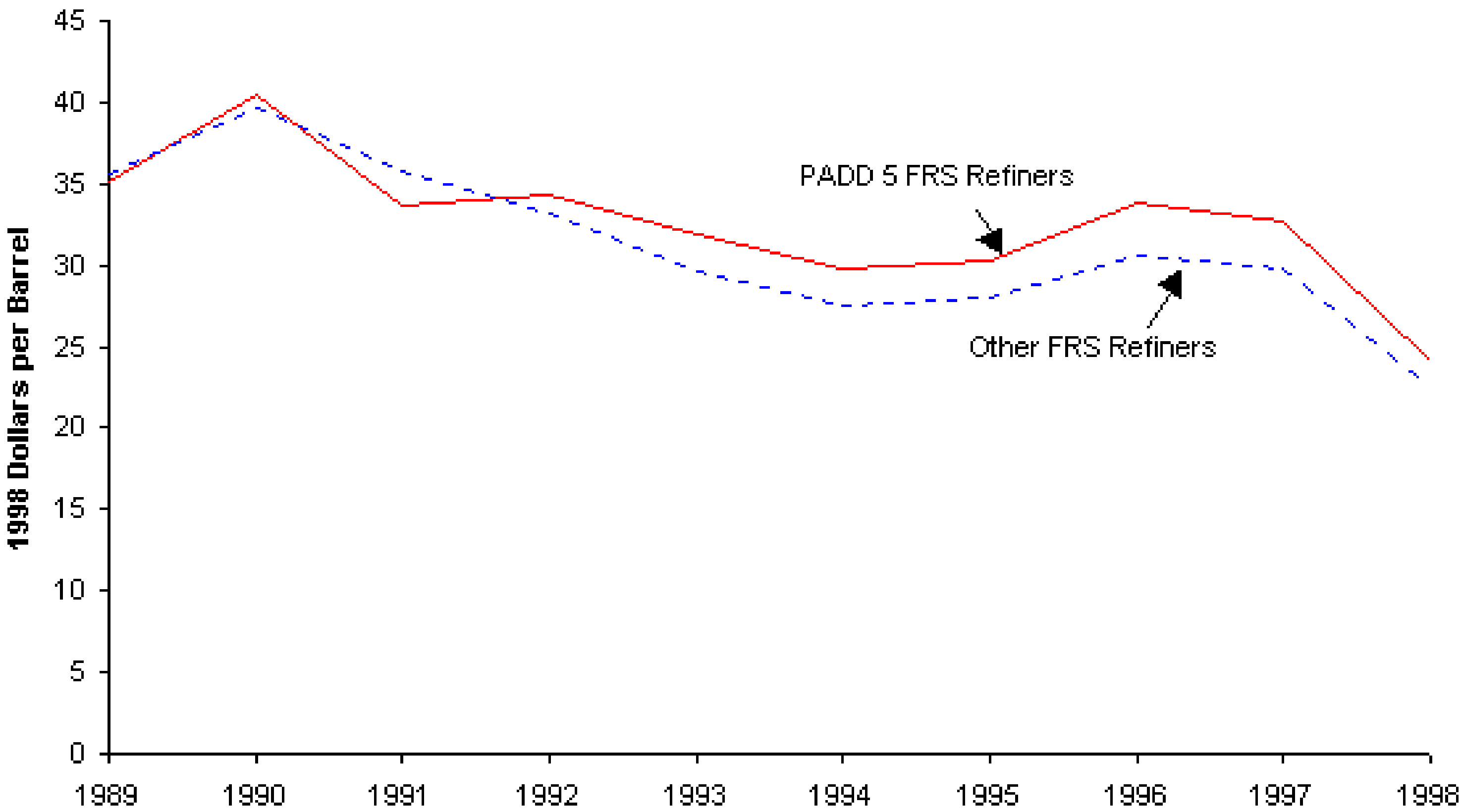
*Last Updated on 12/9/99*

**Figure 17. U.S. Refining/Marketing Return on Investment for PADD 5 FRS Refiners and Other FRS Refiners, 1989-1998**



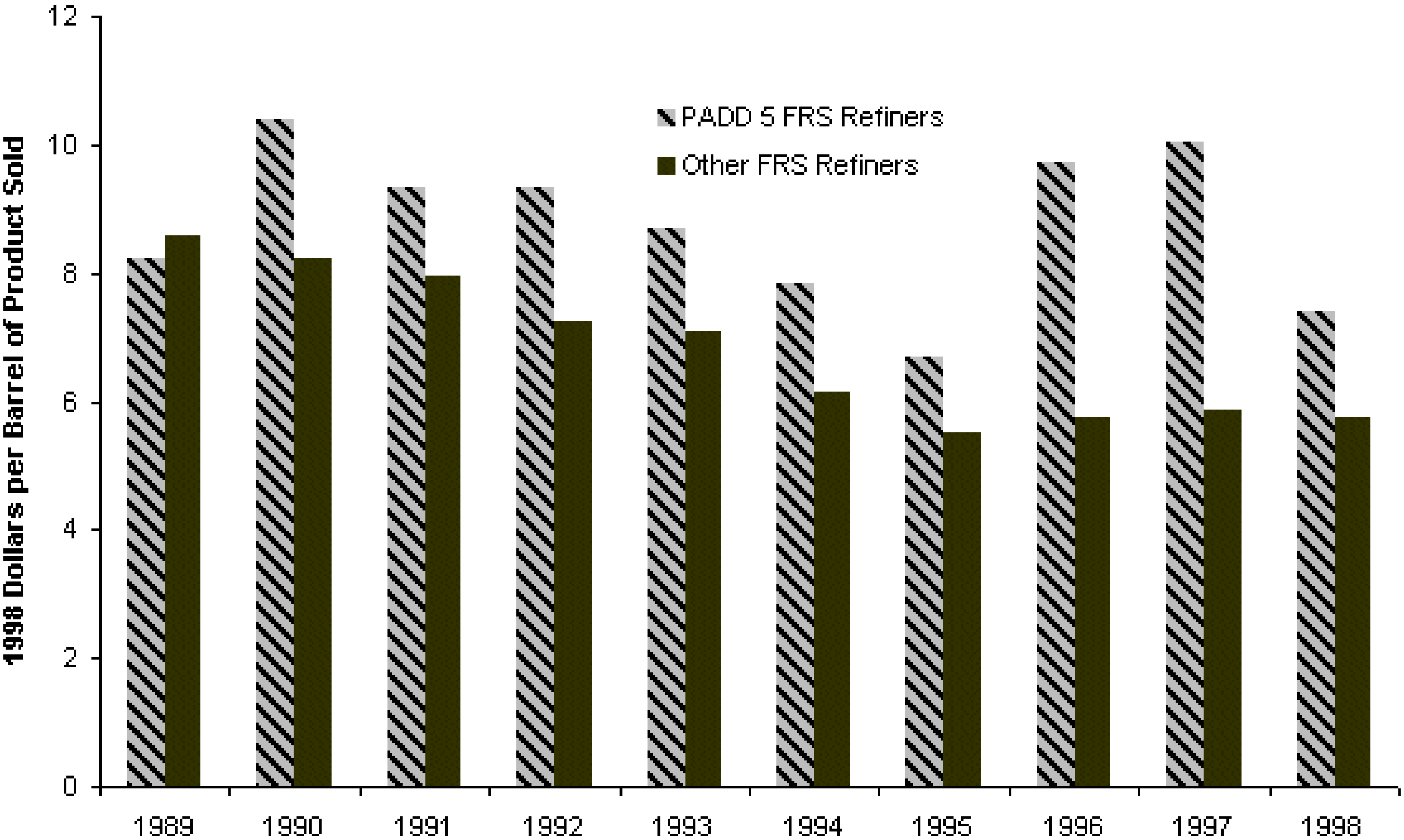

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

**Figure 18. Average Motor Gasoline Price for PADD 5 FRS Refiners and Other FRS Refiners, 1989-1998**



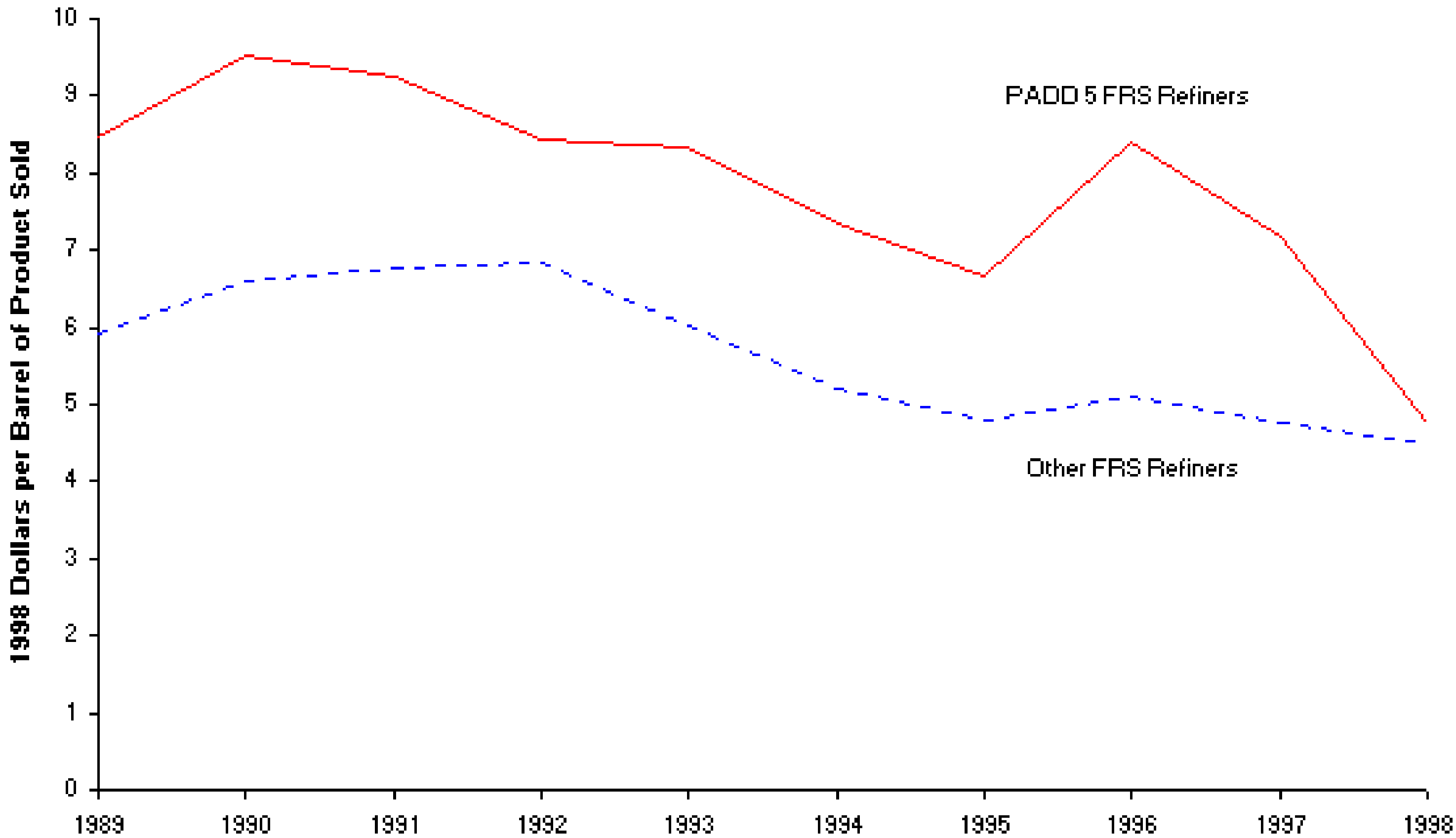

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

**Figure 19. Gross Margin for PADD 5 FRS Refiners and Other FRS Refiners, 1989-1998**




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

**Figure 20. Refining/Marketing Operating Costs for PADD 5 FRS Refiners and Other FRS Refiners, 1989-1998**




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

# 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 enable examinations 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 these uses.

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.

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. However, actual changes in the FRS companies' performance between 1997 and 1998 may be obscured because the data values for 1998 reflect dramatic growth (almost 50 percent) in the number of FRS companies (see the Preface of this report for more discussion of this point).

## The Changing Nature of the U.S. Majors

This chapter of *Performance Profiles* provides a window to current and substantial changes occurring in the U.S. energy industry. Changes in 1998 largely focused on domestic operations. Of particular note were the growing importance of the now-large independent refiner/marketers in the United States and energy company investment initiatives largely related to deregulation of the U.S. natural gas interstate pipeline and electricity industries. To clarify these changes, the analyses (presented below as "Special Topics") discuss:

- the similarities and differences between the U.S. majors of the past two decades and the newest U.S. majors; and
- the movement of natural gas interstate pipeline companies into gas and electric marketing services and the varied patterns of investment by the U.S. majors in domestic interstate natural gas pipelines following deregulation of that industry.

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### *Special Topic:* The Changing Profile of the U.S. Majors -- Is Smaller Better?

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The 1998 reporting year was a significant year for the Financial Reporting System (FRS). Eleven companies were added to the FRS (entrants), most of which are refining/marketing companies (Table 21). Together with the 22 companies in the FRS group in 1998 and before (incumbents), the FRS contains the largest group of respondents in its 25 years of data collection.

In recent years several incumbent FRS companies consolidated or exited U.S. refining and marketing. Reasons for the accompanying divestitures included low returns on investment, low refined product margins, and efforts to reduce operating costs by consolidating refining and marketing operations. The refining and marketing assets divested by incumbent FRS companies were mostly acquired by relatively small, specialized, but rapidly growing refiners, many of which entered the FRS survey as respondents in 1998 ("entrant FRS companies"). Between 1991 and 1998, the entrant FRS companies' refinery capacity increased nearly fourfold and their share of total U.S. refining capacity grew from 9 percent to 36 percent. The addition of the entrants to the FRS group increased coverage of domestic refining to 86 percent of total U.S. capacity in 1998.

Many of the entrants were members of the fast-growing independent refiners/marketers that were discussed in last year's edition of *Performance Profiles* (pdf format).[a] However, last year's discussions principally focused on the substantial refining capacity (and, to a lesser extent, the many retailing outlets) that the fast-growing independent refiners acquired since 1990, mainly from the FRS incumbents(Table 22). Now that most of the fast-growing independent refiners have joined the ranks of the major U.S. energy companies (and thus the FRS survey), a closer examination of these companies through comparison with incumbent FRS companies seems in order.

## Entrants Are Smaller, and Incur More Debt

Foremost, the entrant FRS firms are much smaller than are the incumbent FRS companies. For example, during 1998 the entrant FRS companies' average total corporate assets were $49 billion, while the incumbent FRS companies averaged $364 billion for total assets, more than 7 times greater than that of the entrants.[b] Also, the entrants are much less diversified in their operations than are the incumbents, who operate in significantly more lines of business than do the entrants. (See the introduction of Chapter 2 and Table 2 for amplification of this point.) In general, the entrant firms are not involved in foreign lines of business; they are preponderantly domestic refining/marketing companies.[c]

A striking contrast, which becomes apparent when the financial operations of the entrants are compared with those of the incumbents, is that the two groups raise and spend cash differently (at least during 1998). During 1998, the incumbents raised an unusually large amount of cash though the sale of assets, many of which were purchased by the entrants. The incumbents still raised most of their cash from their ongoing operations during 1998, a long-time tendency (Table 23). Between 1993 and 1997 the average share of cash generated from ongoing operations was 67 percent. Over the same period the average share of cash raised through asset disposals was 11 percent.[d] Therefore, had 1998 been a more typical year, the percentage of cash raised through ongoing operations would have been even greater and the percentage raised through asset sales much lower. Conversely, the entrants raised most of their cash by issuing long-term debt. The entrants generated one third of their cash through ongoing operations and only 10 percent through the disposal of assets and selling of stock.

The two groups of firms were somewhat more similar in the ways in which they used their cash during 1998, although the entrants spent proportionately much more of their cash reducing their long-term debt. Given their greater reliance on debt financing, this is not surprising. The entrants tended to expand their capital stock, pay dividends to stockholders, and purchase treasury stock proportionately less than did the incumbents.

## Lower Costs Are Only One of Many Differences

The margins and costs of the refining/marketing operations of the two groups of FRS companies showed some contrast in 1998. (The net refined product margin (net margin) is the gross margin (refined product revenues minus purchases of raw materials input to refining and refined product purchases per barrel of refined product sold) minus out-of-pocket operating costs per barrel of refined product sold. The net margin is an indication of the degree to which refining and marketing petroleum products add to before-tax cash earnings.) The net margin of the entrants was larger during 1998 than was the net margin of the incumbents, $1.65 per barrel vs. $1.53 per barrel (Table 24). However, the gross margin of the entrant FRS firms was 75 cents per barrel less than the gross margin of the incumbent FRS firms.

The entrants' net margin was higher than the incumbents' net margin because the entrants' out-of-pocket costs (i.e., marketing, energy, and other operating costs) were lower. In particular, the marketing costs of the entrants were significantly lower than were the marketing costs of the incumbents. One of the major reasons that the entrants' marketing costs were lower is that these companies rely more on wholesalers to market their motor gasoline; half of the incumbents' gasoline sales are through wholesalers compared to 64 percent for the entrants (Table 25).[e] Hence, the entrants received a lower average price for motor gasoline than did the incumbents ($21.73 and $22.87 per barrel, respectively) (Table 17).

Reliance on wholesale distribution, mainly sales to jobbers, is just one example of the way the two groups market motor gasoline differently. Lessee and open dealers are a more important marketing channel for the incumbent FRS companies than for the entrants. Although approximately 70 percent of both the incumbents' and the entrants' branded outlets are dealers, the volume of gasoline sold through the incumbents' dealers is much greater than the volume sold through the entrants' dealers (Table 18). Thus, the entrants' dealer outlets are much smaller (measured by average monthly sales volume) than the dealer outlets of the incumbents, selling 39-percent less gasoline. The lower sales volume may indicate that the dealers of the entrant FRS companies have somewhat higher costs than do the dealers of the incumbents because their operating costs are spread over fewer gallons of gasoline sales.

The addition of the entrants to the FRS obviously introduces a large number of companies with many differences from what may be considered the average FRS company profile of the last two decades.[f, g] The addition of the entrant FRS companies has marginally moved the FRS average company profile along a continuum from very large, vertically-integrated energy companies with global operations to smaller, more specialized, less vertically-integrated energy companies oriented more toward domestic operations.[h]

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a See the "Special Topic: U.S. Downstream Independents Acquire National Prominence in the 1990's" in Chapter 4 of Energy Information Administration, *Performance Profiles of Major Energy Producers 1997* (pdf format), DOE/EIA-0206(97) (January 1999, Washington, DC), pp. 60-64.

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

c Sunoco's coal operations and Ultramar Diamond Shamrock's Canadian refining/marketing operations are exceptions. So, too, are most of Williams Companies' operations, which is a communications and energy services company. Williams has refining and marketing operations, but they are, at best, the third most important of Williams' energy operations. Williams also has foreign operations in telecommunications in Australia and Brazil and in oil and gas operations in Lithuania and Venezuela.

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

e Citgo and Valero rely almost exclusively on wholesalers to market their petroleum products. Citgo has more than 14,000 branded gasoline retail outlets, but almost none are company-operated or dealer stations. Valero sells all of its refined petroleum products through wholesalers.

[f] There is no average FRS company, *per se*. Instead, use of the term merely refers to a mathematical average company.

[g] As John D. Rockefeller, Jr. might have said, "These are not my father's companies."

[h] The entrants did increase the FRS share of U.S. refining from 59 percent in 1997 to 80 percent in 1998.

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## *Special Topic:* Interstate Natural Gas Pipelines--Restructuring in the 1990's

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In the 1990's, a number of regulatory and energy market developments affected the operations and structure of the natural gas pipeline industry. Perhaps the most important regulatory development was the Federal Energy Regulatory Commission's (FERC) issuance of Order 636 in April 1992. Deregulation in the U.S. electricity market also impacted the industry by enhancing the potential for a single company to market both electricity and natural gas.

Order 636 (which became effective on November 1, 1993) essentially required the interstate natural gas pipeline industry to unbundle its sales and transportation services and revised the rate design for transportation services.[a] Because Order 636 required the pipelines to separate their sales and transportation services, pipeline revenues were negatively affected. Nonetheless, the profitability of the companies was not necessarily affected as the Order allowed companies to recover most of their costs in fixed demand charges. However, according to a recent report by the Energy Information Administration, Corporate Realignments and Investments in the Interstate Natural Gas Transmission System,[b] overall pipeline revenue fell $7.3 billion (a 41-percent decline) in 1997 compared to 1992 while volumes of natural gas delivered increased by 5 trillion cubic feet. (1992 was the last year before full implementation of Order 636.)

The unbundling of services also led interstate natural gas pipelines to reorganize their business operations. Within the FRS group in 1991, prior to Order 636, Burlington Resources, Coastal, and Occidental Petroleum were significant owners of interstate natural gas pipelines. In 1998, Coastal, Enron, Sonat, and Williams Companies were the FRS companies involved in interstate natural gas pipelines. Some companies set up affiliated marketing subsidiaries to manage the buying and selling of natural gas for customers who previously purchased gas directly from the pipeline. Subsequently, some of these subsidiaries have become major marketers. For example, Enron Corporation's (an FRS respondent) subsidiary, Enron Capital and Marketing Inc., has become the largest natural gas marketer in North America[c] with transactions totaling more than $11 billion in 1997. These operations accounted for nearly 58 percent of Enron Corporation's total operating revenues.

Order 636 also had major impacts on the investment profile of the interstate natural gas pipeline industry. Some pipeline companies sought marketing and operational synergies through mergers and acquisitions, and/or internally restructured to better respond to increased competition in the industry. For the 14 corporations[d] owning the bulk of interstate natural gas pipelines, the majority of their growth in these operations in recent years was achieved through mergers and acquisitions. Interstate natural gas pipeline assets owned by these 14 corporations increased by 85 percent between 1992 and 1997; with three corporations primarily responsible for most of these acquisitions: Duke Energy, El Paso Energy, and Williams Companies (an FRS respondent).

One apparent aim of these transactions was to extend the companies' natural gas transportation services nationwide. Duke Energy acquired Pan Energy Inc. in 1997. El Paso Energy acquired Tenneco Energy in December 1996[e] and Williams Companies purchased Transco Energy Company in May 1995. This transaction by Williams Companies made it the largest transporter of natural gas in the nation in 1998.[f] Subsequently, the October 1999 merger between El Paso Energy Corporation and Sonat (an FRS company) overturned this achievement, as the newly combined company (El Paso Energy Corporation) is now the largest transporter of natural gas in the country.[g]

Deregulation in the U.S. electricity market has pushed the gas transmission industry into new operational and ownership configurations. For example, for the 14 corporations with interstate natural gas operations noted above, the most frequently occurring line-of-business activity was energy (natural gas and electric) marketing and services (excluding natural gas transmission and storage operations). Twelve of the fourteen parent corporations were engaged in energy marketing and services operations.

Of these twelve parent corporations, four were engaged in integrated electric services (operations in generation, transmission, and distribution). Recently, a number of mergers have combined downstream natural gas operations with integrated electricity operations. For example, Enron Corporation purchased Portland General Corporation, a wholly owned subsidiary of Portland General Electric in 1997. As a result of this transaction, Enron became the largest wholesaler of gas and electricity in North America and the largest investor-owned electric utility company in 1997. Duke Energy acquired PanEnergy, and then sold a 40-percent interest in its marketing division to Mobil, an FRS respondent and a major producer of natural gas. Houston Energy merged with Noram Energy in 1997 and, in 1998, renamed the company Reliant Energy Corporation. Pacific Gas and Electric acquired Valero Energy's natural gas transmission assets.[h] Other corporations, such as Sonat created a marketing division (prior to their merger with El Paso Energy Corporation) to take advantage of the opportunities in wholesale power marketing.[i]

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a For a more detailed explanation and review of Order 636, see Energy Information Administration, *Natural Gas 1994: Issues and Trends*, (pdf format) Chapter 2, DOE/EIA-0560(94)(Washington, DC, July 1994), online at ftp://ftp.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/natural_gas_1994_issues_trends/pdf/056094.pdf.

b This report reviews the financial characteristics of current ownership within the natural gas pipeline industry and of the major interstate pipelines that transport the bulk of natural gas consumed in the United States between 1992 and 1997. It looks at how these corporations have changed in recent years and how they have reformed themselves to meet the demands of doing business in today's marketplace. It also includes an analysis of the near-term investment needs of the industry and the anticipated growth in demand for natural gas over the next decade. The potential natural gas transmission investment capabilities in the near-term for the 14 parent corporations relative to the investment potential of large U.S. corporations are examined. The report was electronically released in September, 1998 (see http://www.eia.doe.gov/emeu/finance/sptopics/ng_realign&invest/index.html and also published in the EIA *Natural Gas Monthly* (November 1999).

c Enron Capital and Marketing Inc.'s affiliated pipelines are Northern Natural Gas Company, Transwestern Pipeline Company, and Mid-Louisiana Gas Company.

d The 14 parent corporations discussed in this report include: Coastal Corporation, Columbia Energy Group, Consolidated Natural Gas, Duke Energy Corporation, El Paso Energy, Enron Corporation, KN Energy Corporation, MDU Resources

Group, Northern States Power Company, PG&E Corporation, Reliant Energy Corporation, Questar Corporation, Sonat Corporation, and Williams Companies, Incorporated. Four of these corporations are FRS respondents: Coastal, Enron, Sonat, and Williams Companies.

[e] El Paso Energy Corporation, "Company Profile," online at http://www.epenergy.com/about/profile.htm.

[f] The Williams Companies, "Natural Gas Services," online at http://www.williamsenergy.com/Energy/ngs/frameset/naturalgas.htm.

[g] El Paso Energy Corporation "El Paso Corporation and Sonat Inc. Complete Merger Create the Largest Natural Gas Pipeline System in North America" (October 25, 1999), and Dow Jones Newswires "DJ El Paso Energy, Sonat Complete Merger" (October 25, 1999).

[h] Energy Information Administration, *Performance Profiles* (pdf format), Table 19.

[i] Sonat Incorporated, *1997 Securities and Exchange Commission, Form 10-K*, p. I-21.

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## *Special Topic:* U.S. Pipelines -- Are the Majors Moving Toward Natural Gas?

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In recent years, and in 1998 especially, the involvement of FRS companies in U.S. natural gas pipelines has been in a state of flux. Some FRS companies have acquired assets or merged with other natural gas companies whereas other FRS companies have sold their natural gas pipeline operations. In 1998, natural gas pipeline assets accounted for 74 percent of total rate regulated pipeline assets of the FRS companies compared to 61 percent in 1997. This 13-percent increase in natural gas pipeline assets can be attributed to two companies (Shell Oil and Williams Companies) reporting natural gas assets for the first time in 1998. However, asset growth was slightly offset in 1998 (less than 1 percentage point) by Occidental Petroleum's January 1998 sale of Midcon, its wholly owned natural gas transmission and marketing company.[a] With the addition of these two companies reporting natural gas assets, the FRS group in 1998 contains five companies: Coastal, Enron, Shell Oil, Sonat, and Williams Companies. In 1998, these five companies had a delivery capacity of approximately 41 billion cubic feet per day (bcf/d) of gas, which accounted for nearly 32 percent of interstate natural gas pipeline capacity.[b]

In 1998, Williams Companies' acquisition of MAPCO brought it into the ranks of the FRS respondent group. The refining and marketing assets acquired by the company through MAPCO were pivotal in the selection of the Williams Companies as an FRS respondent. However, Williams is also a major player in interstate natural gas pipelines. The company owns 5 major interstate pipeline operations and the pipelines are operated through its wholly owned subsidiary, Williams Gas Pipeline Company. The interstate natural gas pipelines are Transcontinental Gas Pipeline Corporation (northeast region), Northwest Pipeline Corporation (western region), Kern River Gas Transmission Company (western region), Texas Gas Transmission Corporation, and Williams Gas Pipelines-Central, Inc (midwestern region). Williams Companies has a delivery capacity of approximately 15 bcf/d of gas.[c]

Shell Oil, a long-time FRS company having crude oil pipeline assets, began reporting natural gas assets as a result of its acquisition of Tejas Gas and Tejas Gas's ownership interest in Coral Energy (a gas marketing enterprise) in 1998. Tejas Gas is an intrastate natural gas pipeline company and serves the major gas-producing areas of Oklahoma, South Texas, East Texas and the Gulf Coast regions near Texas and Louisiana. Following the Tejas transaction, Shell Oil combined its natural gas businesses (Coral Energy, Corpus Christi Natural Gas, and Tejas Gas) into a single natural gas business.

Why are companies entering and exiting the natural gas pipeline industry in recent years?

Due to regulations imposed by the Federal Energy Regulatory Commission (FERC), the industry is facing uncertainty as it continues to undergo restructuring brought about through FERC Orders 436 and Order 636. In addition, regulations in the electric power sector (FERC Order 888) have also increased competition for the natural gas industry. Not only are the electric generation companies customers of the natural gas industry, but they have also become competitors as they venture into natural gas marketing.

In order to operate in this new regulatory environment, natural gas companies have implemented strategies that will allow them to survive, prosper and/or take advantage of changes in the industry. Some strategies undertaken by natural gas companies are to pursue growth through mergers, acquisitions, and joint ventures of natural gas assets and/or electric utility assets.[d] For example, Shell's acquisition of Tejas Gas expanded its scope in natural gas transportation and storage, and natural gas liquids processing.[e] In 1999, Sonat's merger with El Paso Energy in October 1999 created the largest natural gas transmission system in the United States.[f] Conversely, Occidental Petroleum sold Midcon, in order to concentrate on core businesses in oil and gas production and chemical operations.

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a Occidental owned the interstate pipeline Natural Gas Pipeline Company of America. Occidental Petroleum Corporation, *1998 Securities and Exchange Commission, Form 10-K*.

b Percentages compiled from Federal Energy Regulatory Commission, *Annual Capacity Report* (18 CFR 284.12).

c Williams Companies, *1998 Securities and Exchange Commission, Form 10-K*.

d Energy Information Administration, *Natural Gas: Issues and Trends 1998* (pdf format) (June 1998), chapter 7.

e Shell Oil Press Release, "Tejas Gas Changes Company Name to Reflect Expanded Scope, Focus," (April 30, 1998).

f El Paso Energy Corporation, "El Paso Corporation and Sonat Inc. Complete Merger Create the Largest Natural Gas Pipeline System in North America" (October 25, 1999).

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## Resource Development Costs and Potential

This chapter of *Performance Profiles* also addresses the costs of finding oil and gas and resource development issues. While finding cost data do not directly affect the current-year bottom line of the FRS companies (see Chapter 3), they are important in guiding the scale and scope of the companies' current and future resource development strategies. Accordingly, this chapter also discusses the geographical areas of most importance to the FRS companies' current resource development initiatives. Specifically, this year's analyses (presented below as "Special Topics") discuss:

- the increase in finding costs, partially due to higher finding costs in mature areas and partially due to reserve revisions made when oil prices were at historically low levels (at the end of 1998);

- the apparent progress in reducing the uncertainty that constrains development of the Caspian basin oil and gas reserves and construction of related transportation infrastructure;
- the growth of oil and gas production in the North Sea and the slowing of Alaska North Slope production declines through a variety of means, including the application of advances in technology and more prudent use of the production infrastructure; and
- the significance of the oil and gas fields coming on line in the eastern portion of Canada.

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## *Special Topic:* A Regional Look at Finding Cost Increases

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Finding costs are the costs of adding oil (crude oil and natural gas liquids) reserves and dry natural gas reserves via exploration and development activity.[a] They are measured for oil and gas on a combined basis in units of dollars per barrel of oil equivalent (BOE). 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 proven 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 proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[b]

To accommodate leads and lags in data reporting, finding costs are generally measured in this report as a moving average over a period of three years in constant dollars. For the FRS companies in the 1996 to 1998 period, worldwide finding costs increased by 18 percent over the level for the 1995 to 1997 period (Table 26). This is the second straight year that worldwide finding costs increased for the FRS companies.

Nonetheless, finding costs for the 1996 to 1998 period were not high compared to recent history, during which finding costs had been falling until the last few years (Figure 21). While U.S. offshore finding costs have risen about $4.50 per BOE in 1998 dollars since their low in the 1993 to 1995 period, they are still equivalent to their mid- to late-1980’s level. Further, U.S. onshore and foreign finding costs have risen less than $1.00 per BOE since their lows in the 1994 to 1996 period.

To see current trends in finding costs more clearly, it is useful to look at finding costs on an annual basis (not as a three-year moving average). When annual finding costs in recent years for each of the FRS regions are examined, the regions clearly fall into two groups, those that experienced sharply rising annual finding costs and those that did not. Canada, OECD Europe, and both onshore and offshore areas of the United States had large increases in annual finding costs between 1994 and 1998 (Figure 22).[c] Although these regions are all mature producing areas, they still remain the regions accounting for a major share of exploration and development spending by the FRS companies. In contrast, annual finding costs in Africa, the Middle East, and the Other Western Hemisphere have risen little since 1994, and they have fallen in the Other Eastern Hemisphere.

Additional insight into the rise in finding costs can be gained by breaking them down into their components. Finding costs are calculated as exploration and development expenditures per well (the sum of drilling costs and other expenditures per well completed) divided by the finding rate. Conceptually, finding rates are the total amount of proven reserves that were added by drilling a group of wells (over the operating lifetime of those wells) divided by the number of wells drilled, including dry holes.[d] In practice, and in this report as well, finding rates are actually measured as the ratio of proven reserve additions (excluding net purchases of proven reserves) to the total number of exploratory and development wells, including dry holes, completed over a specified period of time.

Table 27 shows the contributions of these various components to the percent rise in annual finding costs (in 1998 dollars) between 1994 and 1998 for the four regions with large increases in finding costs over the period: the U.S. onshore, U.S. offshore, Canada, and OECD Europe.

What is striking is the difference between the U.S. regions and the foreign regions. For both the U.S. onshore and U.S. offshore, increased expenditures per well proved to be about twice as important as lower finding rates in their effect on finding costs. In Canada and OECD Europe, the weights of the contributions to increased finding costs are reversed, and even more one-sided. The lower finding rates account, on average, for about 90 percent of the change in finding costs in those two regions. In addition, for the U.S. regions, the increased expenditures per well are primarily caused by increases in other exploration and development costs, not by increased drilling costs.[e] This result was most pronounced for the U.S. onshore.

One possible cause of lower finding rates is that, within a period of time, smaller reservoirs are found as more wells are drilled. This is the expected result of continued increases in drilling during the period, as less and less promising areas are drilled within conventional depth limits. Increased expenditures per well can be the result of increases in the amount or cost of any of the components of exploration and development operations, including drilling, unproven acreage acquisition, geological and geophysical activities, lease equipment, support equipment, and direct overhead costs. For the United States, drilling costs contributed less than half of the increased expenditures per well. This was more notable onshore, where drilling costs were the source of only 40 percent of the increased expenditures per well.

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a Alternatively, finding costs are the costs of replacing reserves removed through production.

b One inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not usually correspond exactly with each other. Expenditures are usually recognized in the period that that the payment actually occurred. Proven reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must occur in the same time period (oil and gas wells are often operated for a long time), so that some expenditures may not be recognized in the same time period that their corresponding reserves are recognized. 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. However, the longer the time period over which finding costs are measured, the more out of date they become, because they include older and older expenditures and reserves, and costs and technology are constantly changing. The only way to solve the correspondence problem would be to calculate an average finding cost for all of the oil and gas produced by a well after it is permanently shut in. But many costs included would be far out of date.

c The Former Soviet Union and Eastern Europe region is not included in these figures because it has not always had reserve additions over the period and its reserve additions are still quite small.

d 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.

e Drilling costs and other exploration and development costs are not available.

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## *Special Topic:* Reserve Revisions Add to Finding Cost Woes

In the 1996 to 1998 period, worldwide finding costs for the FRS companies (measured as a three-year moving average) increased by 18 percent over levels for the 1995 to 1997 period. One of the reasons for the recent rise in finding costs (unrelated to success in exploration and development drilling) is that the collapse in oil prices in 1998 triggered downward revisions in reported reserves by many FRS companies. (Proven reserves are defined as reserves that are estimated to be economically recoverable under current economic conditions.)

Most of the FRS companies publish their reserve estimates as of the end of the year as required by law and regulations, so 1998 estimates were made when crude oil prices were at historically low levels, and 1998 natural gas prices were also down considerably from the end of 1997. Thus, many of the FRS companies revised their estimates of proven reserves downward in 1998 because some reserves were no longer economically recoverable at the lower prices for oil and gas. For example, Phillips Petroleum reported that its negative revisions to reserves were "mainly caused by the current environment of low prices,"[a] and Anadarko Petroleum reported "a negative reserve revision caused by lower natural gas and crude oil prices at year-end 1998 compared to year-end 1997."[b]

For the FRS companies, downward revisions to reserves because of lower oil and gas prices were sometimes offset by upward revisions for other reasons. The net result was that 12 of 23 FRS companies reporting oil reserves and 12 of 24 FRS companies reporting gas reserves at year-end recorded negative net reserve revisions to proved oil and gas reserves. In total, revisions to oil reserves for the FRS companies were a positive 500 million barrels, and revisions to gas reserves were a positive 2,100 billion cubic feet in 1998. The revisions to gas reserves were similar to the previous five-year average level of revisions, but revisions to oil reserves in 1998 were 300 million barrels less than the previous five-year average. With oil prices falling proportionally more than gas prices in 1998, the effect of the price decline on proven oil reserves was much more serious than its effect on proven gas reserves.

The unusual amount of downward reserve revisions in 1998 pushed finding costs higher than they would have been otherwise, because net revisions to reserve estimates are included in the calculation of finding costs. To estimate this effect, reserve revisions were calculated for the four regions with increased annual finding costs over the years 1994 to 1998--Canada, OECD Europe, and both the onshore and offshore areas of the United States. (See the Special Topic entitled "A Regional Look at Finding Cost Increases" in Chapter 4 for a more detailed discussion of finding cost increases in these regions.)

It was assumed that, in 1998, the ratio of reserve revisions to beginning-of-the-year reserves was the same as its average for the previous five years instead of the amounts actually reported. This assumption yielded decreases in estimated 1998 finding costs of more than $2 per barrel of oil equivalent (BOE) in Canada, more than $1 per BOE in OECD Europe, and about $0.60 per BOE for the U.S. onshore region. Interestingly, the assumption resulted in a $0.65-per-BOE increase in finding costs for the U.S. offshore. This result occurred because reserve revisions in the offshore in 1998 were actually less than the average for the previous five years, suggesting that, in the United States, most downward revisions of proven reserves were made to onshore properties.

In total, the FRS companies added 4.4 billion barrels of oil and 20.4 trillion cubic feet of gas (including net purchases) to worldwide reserves in 1998 (Table 28), or 8.0 billion BOE in total. This is the largest amount of reserves added on a BOE basis since at least 1974, the first year that FRS data were collected.

Considering only reserves added through the drill bit, the increase in 1998, 6.1 billion BOE, was still large--the third largest since 1977. (Most of these reserves were likely the result of exploration and development projects started before the collapse of oil prices in 1998.) Some of the largest reserve increases through the drill bit were by Exxon, Mobil, Enron, and Anadarko. Exxon revised upward its gas reserves substantially for the United States and for the Asia-Pacific Region, and also made large additions to its oil reserves through extensions and discoveries.[c] Mobil increased its proven oil reserves with large extension and discovery additions of heavy oil reserves at the Cerro Negro field in Venezuela.[d] Anadarko Petroleum made large new discoveries of gas in the sub-salt trend in the Gulf of Mexico.[e] Enron made substantial gas extensions and discoveries in India, where gas production more than tripled in 1998, and on the U(a) block in Trinidad.

Mergers and acquisitions had a large effect on reserves. Three large contributors to FRS company reserve increases through purchases in 1998 were the acquisitions of Oryx Energy by Kerr-Mcgee, the Federal Government's Elk Hills property by Occidental Petroleum, and Union Texas Petroleum by Atlantic Richfield. Overall, net purchases of reserves added 1.2 billion barrels of oil and 4.5 trillion cubic feet of gas to the total reserves of the FRS companies in 1998.

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a Phillips Petroleum, *1998 Annual Report*, p. 11.

b Anadarko Petroleum, *1998 Securities and Exchange Commission, Form 10-K*, p. 65.

c Exxon, *1998 Annual Report* (October 20, 1999).

d Mobil, *1998 Annual Report*, p. 16.

e Anadarko Petroleum, *1998 Securities and Exchange Commission, Form 10-K*, p. 66 and *1998 Annual Report*, (November 1, 1999).

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## ***Special Topic:*** **The Caspian -- Will the Payoff Be Worth The Risk?**

The nations in the Caspian Sea region include Azerbaijan, Iran, Kazakhstan, Russia, Turkmenistan, and Uzbekistan. With the exception of Iran, all of these countries were part of the former Soviet Union. Under the former Soviet Union, oil and gas exploration and development in the region languished because of security concerns as well as technological and capital constraints.

While underdeveloped, the Caspian's endowment of oil and gas resources has generally been believed to be enormous. Although the region's level of proven oil reserves is roughly 16 to 32 billion barrels, the level of total oil resources (proven plus possible reserves) has been estimated to be in the range of 179 to 195 billion barrels.[a] Further, the region's gas resources are believed by some to exceed 500 trillion cubic feet.

The lack of pipeline infrastructure needed to transport the Caspian's oil and gas production out of the region remains one of the primary impediments to exploration, development, and production of the region's resources. Most of the existing oil export pipelines terminate at the Russian Black Sea port of Novorossiisk, requiring tankers to transit the crowded and ecologically and politically sensitive Bosporus--a 20-mile strait with 12 turns through which ships must navigate to reach the Mediterranean and world markets. Because of this bottleneck (as well as other factors), transportation costs out of the region are in range of $4 to $8 dollars per barrel, effectively making all but the most promising prospects uneconomic given current prices.[b]

Moreover, there are political and security concerns as to whether producers should be reliant on Russia for their sole export outlet. The U.S. government has advocated multiple oil pipeline routes out of the region. Nevertheless, it is the view of many industry observers that a pipeline to Asia's population centers would be too expensive given the distances involved.[c] A pipeline through Iran to the Middle East is also of questionable economics given that that region is a competitor with the Caspian.[d] Accordingly, the goal of multiple export routes reduces to pipelines going west. However, the economic viability of this outcome is dependent, in large part, on the amount of hydrocarbons actually discovered, their location, and the proportions of oil and gas found. The composition (in terms of oil vs. gas) of hydrocarbons discovered is important since transporting oil by pipeline is more economical than transporting natural gas.

As of the end of 1998, the region's early promise was clouded; while a number of production- sharing agreements have been signed and exploratory wells drilled, there have been no major discoveries. Some observers have taken the disappointing drilling results as evidence that the region's potential has been overstated. Despite this growing pessimism, a number of the companies, most notably BP Amoco, have largely stayed the course in terms of their Caspian strategy.

Another impediment to the development of the oil and gas resources of the Caspian Sea is the longstanding issue of the legal ownership of the seabed resources. Azerbaijan, Kazakhstan, and Turkmenistan, the three nations that are generally believed to have oil near their coastlines, have advocated dividing the Caspian into national sectors. Russia and Iran, which are generally believed to have little or no oil near their coasts, have argued for sharing the Caspian's resources.

The year 1998 saw some movement in the resolution of this dispute. Specifically, in July 1998, Russia and Kazakhstan signed an agreement that divides the northern part of the Caspian Sea seabed into separate Russian and Kazakh sectors, thereby recognizing Kazakhstan's claim to the oil near its coastline. While Azerbaijan, Turkmenistan, and Iran were not parties to the settlement, it may set a precedent for future agreements.

### *Azerbaijan*

**The Azeri-Chirag-Guneshli Project.** The Azerbaijan International Oil Consortium (AIOC), a consortium composed of the State Oil Company of the Azerbaijan Republic (SOCAR) and a group of 11 companies (including BP Amoco, Exxon, Pennzoil, and Unocal) signed an $8-billion, 30-year contract in September 1994 to develop these Caspian Sea fields. The fields have estimated recoverable resources of 3 to 5 billion barrels. Production from the project commenced in December 1997. For the entire year, production from the project was exported through an existing pipeline, the so-called northern route, which runs from Baku to the Russian Black Sea port of Novorossiisk. As 1998 ended, oil was also being exported through a newly rehabilitated pipeline known as the western route. This pipeline stretches from Baku to the Black Sea port of Supsa in Georgia. As of the end of the year, production from the project was approximately 75,000 barrels per day.

The project is believed to have a potential of 800,000 barrels per day. Attaining this potential will require the construction of a main export pipeline. AIOC is considering three alternative routes: Baku to the Georgian port of Supsa, (estimated cost: $1.8 billion), Baku to the Russian port of Novorossiisk (estimated cost: $2.5 billion), and Baku to the Turkish port of Ceyhan (estimated cost: $3.7 billion). As the year closed there were indications that a decision on the main export route may be delayed until there are more indications concerning the amount of oil that the region can produce.

**The Shah Deniz contract area.** Geologists first identified this prospect in 1954. Recoverable resource estimates for the prospect range from 1.5 to 3 billion barrels of oil and up to 350 billion cubic feet of gas. It is situated in the South Caspian Sea, approximately 42 miles southeast of Baku. The water depth of the prospect ranges from approximately 150 feet in the northwest to almost 2,000 feet in the southeast. The contract area covers an area approximately 320 square miles. The operator of the project is BP Amoco (with a 25.5-percent ownership interest). Other participants in the project include Statoil (25.5 percent), SOCAR (10 percent), and Elf Petroleum (10 percent), Iran's Oil Industries Engineering and Construction (OIEC) Company (10 percent), and Turkish Petroleum Overseas Company, Ltd. (9 percent).e

Exploratory drilling commenced in July 1998. Using a semi-submersible drilling rig, the well encountered significant volumes of natural gas condensate. The discovery of gas as opposed to oil could have major implications for the pace and pattern of development in the overall region. It may mean that there is not enough oil to justify the key U.S. objective of having multiple oil pipeline routes to the West. It also may also adversely affect the prospects of developing the natural gas resources of Turkmenistan.

**Oguz.** The exploration and production agreement for this prospect was approved by Azerbaijan's parliament in late 1997. Under the agreement, Mobil and SOCAR each have a 50-percent stake in the field, which is located about 50 miles southeast of Apsheron Peninsula in the Caspian Sea. Recoverable resources are estimated at 733 million barrels of oil.

**The Alov, Araz and Sharg contract areas.** An agreement was signed with the Republic of Azerbaijan that provides a consortium of companies led by BP Amoco with exploration, development, and production rights to this approximately 520-square-mile area of the Caspian Sea which is located about 72 miles southeast of Baku. This contract area is the largest granted to date in Azerbaijan's sector of the Caspian Sea. Indicative of the area's potential, the size of the area corresponds to the geological structures believed to contain hydrocarbons. Under the terms of the agreement, three wells will be drilled by 2001, with up to five additional exploration wells by 2004.

**The Inam contract area.** An agreement was signed which will lead to exploration and development of this Caspian Sea prospect by a consortium of companies whose members include BP Amoco, SOCAR, Monument Resources, Ltd. and Central Fuel Caspian Sea, Ltd. BP Amoco will operate the consortium during the exploration phase and a SOCAR (50 percent)-BP Amoco (50 percent) operating company will take over during the development phase.

**Karabakh.** Exploration of this prospect was being conducted by the Caspian International Petroleum Company, a consortium of companies whose members included Agip, LUKAgip, LUKoil, Pennzoil, and SOCAR. While the estimated recoverable resources of the prospect exceeded one billion barrels, the results of drilling indicated less than commercial quantities of crude oil. The project was suspended in late 1998 and the consortium was disbanded in early 1999.

**Dan Ulduzu and Ashrafi.** Exploration of these prospects was conducted by the Northern Apsheron Operating Company, a consortium of companies whose members included BP Amoco, Delta, Itochu, and SOCAR. Despite recoverable estimates of approximately one billion barrels, exploratory drilling failed to indicate a commercial deposit. The consortium has also been disbanded.

**Yalama.** LukArco, the ARCO-Lukoil joint venture, signed an agreement in early 1998 to assume Lukoil's 60 percent interest in this approximately 370-square-mile block located about 150 miles northwest of Baku in the Caspian Sea. Seismic data on the block were collected in 1998.

### *Kazakhstan*

**Tengiz.** With six billion barrels of proven reserves, the Tengiz oil field is one of the world's largest oilfields. The field is operated by Tengizchevroil, a joint venture among Chevron (45 percent), Mobil (25 percent), the government of Kazakhstan (25 percent), and Lukoil (5 percent). Since the venture commenced in 1993, more than $1.3 billion has been invested to increase production capacity to 215,000 barrels a day. Production from Tengiz averaged 200,000 barrels per day in 1998, up from 30,000 barrels per day in 1993 when the joint venture was formed. More than half of the oil produced from the project has moved by rail.

Since the costs of shipping oil by rail tend to be unattractive, a venture known as the Caspian Pipeline Consortium (whose U.S. owners include Mobil (7.5 percent), Chevron (15 percent), and Oryx (1.75 percent)) is planning a 900-mile pipeline from the Tengiz field to the port of Novorissiisk on the Black Sea. Oil shipments were scheduled to begin in late 1999, but the Western partners in the Tengiz project suspended the project's funding in early 1998 upon learning that Russian rights of way and other various federal and local permits for the pipeline had not been obtained. After winning approval by the Russian and Kazakh government of the construction feasibility studies in late 1998, the Tengiz project is now scheduled for completion in 2001. The pipeline is expected to allow the project to reach its full potential of almost 700,000 barrels a day in 10 years.

**Karachaganak.** In late 1997, the government of Kazakhstan signed an agreement with a consortium that includes Texaco, British Gas, Italy's Agip, and Russia's Lukoil to develop this oil and natural gas field in northwestern Kazakhstan near the border with Russia. The field's recoverable resources are estimated at more than 2 billion barrels of crude oil and about 20 trillion cubic feet of natural gas. As of August 1998 the field was producing 70,000 barrels per day with production rising as a result of an aggressive field development program. The project is believed to have a potential capacity of 260,000 barrels of oil per day. It is expected that most of field's production will be exported to the West via the Caspian Pipeline Consortium's pipeline. Until this pipeline is complete, however, most of the production has been exported to Russia.

**Kashagan.** This prospect is located in the North Caspian Sea. The project is operated by the Offshore Kazakhstan International Operating Company (OKIOC), whose owners include Phillips Petroleum, Japan's Inpex, Italy's Agip, British Gas, BP Amoco, Statoil, Mobil, Shell and Total. Under the production-sharing contract, the Kazakh government will receive 80 percent of all profits from the project.f The field is located about 50 miles from the giant Tengiz oil field. The estimated recoverable reserves of the field are staggering--more than 25 billion barrels. As of the end of 1998, almost $500 million had been spent on seismic and other preparatory work.[g] Exploratory drilling was expected to commence in early 1999 but was delayed until later in the year. The results of the drilling will not be known until early 2000.

### *Turkmenistan*

**Garashsyzlyk.** Mobil entered into a production-sharing agreement with the government of Turkmenistan that gives it the right to pursue exploration and development opportunities in this approximately 1700-square-mile area located in the onshore region of Western Turkmenistan. The block is an onshore continuation of the prolific Apsheron trend in the South Caspian Sea. It lies immediately adjacent to the Nebitdag concession, which is now producing oil for export and in which Mobil has a 40-percent interest.

**Daulatabad.** This gas field is located in southeastern Turkmenistan. A consortium known as Centgas had been established to construct a $2-billion, 800-mile pipeline that would transport the gas through Afghanistan to Pakistan. Unocal had a 54-percent interest in the pipeline project; however, citing business reasons, Unocal withdrew from the project in late 1998. Factors that may have contributed to the decision include the low oil price environment and human rights issues in Afghanistan.

**TransCaspian Gas Pipeline System.** BP Amoco announced plans for this project, which will transport natural gas from Turkmenistan to markets in Turkey and Europe.[h] The $2.4-billion, 750-mile pipeline will extend across the Caspian Sea basin to Baku, Azerbaijan. The line will continue across Azerbaijan and Georgia to Turkey. The pipeline will have an initial capacity of 350 billion cubic feet per year, eventually increasing to 1.225 trillion cubic feet per year. Construction is expected to take three years. Iran has criticized this project, indicating that it would breach the rights of the littoral states.

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**a Energy Information Administration, Caspian Sea Region analysis brief (December 1998).**

**b Alexander Woostmänn, "Plans for pipelines everywhere around the Caspian, but for what oil?", *Alexander's Oil and Gas Connections*, Volume 4, Number 8 (April 28, 1999).**

**c Under one option, the pipeline going east would be approximately 1,800 miles long and cost $10 billion. See Alexander Woostmänn, "Kazakh official says oil pipeline to China not feasible under current conditions," *Alexander's Oil and Gas Connections* Volume 4, Number 15 (September 8, 1999).**

**d Moreover, the construction of a pipeline through Iran is problematic given that U.S. Presidential Executive Orders signed in 1995 prohibit U.S. companies from conducting business with Iran. In addition, the U.S. Iran and Libya Sanctions Act of 1996 imposes sanctions on non-U.S. companies that make large investments in the Iranian oil and gas sectors.**

**e BP Amoco, "BP Amoco Major Gas Condensate Find in Azerbaijan" (July 12, 1999).**

**f Alexander Woostmänn, "Kazakh government, investors express high hopes as OKIOC begins drilling," *Alexander's Oil and Gas Connections*, Volume 4, Number 17 (October 8, 1999).**

**g Alexander Woostmänn, "OKIOC does first test drill in Caspian seabed," *Alexander's Oil and Gas Connections*, Volume 4, Number 17 (October 8, 1999).**

**h BP Amoco, " Consortium Formed to Develop and Operate New Transcaspian Gas Pipeline - Pipeline Will Transport Natural Gas From Turkmenistan to Turkey" (June 29, 1998).**

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## *Special Topic:* The North Sea -- Development Outpaces Exploration

**In the early 1990s, exploration drilling by the FRS companies in the North Sea, as proxied by their overall level of drilling in OECD Europe, outpaced development drilling (Figure 23).[a] Since then, the pattern has reversed. This increased emphasis on development was especially evident in 1998 when development drilling was 45-percent higher than in 1997 while exploration drilling was 26 percent lower. This shift in favor of development bodes well for the level of production from the North Sea over the short to intermediate run. Some of the projects supported by the increase in development drilling are:**

**Britannia. This field is located 130 miles northeast of Aberdeen, Scotland. With an area of approximately 70 square miles, it represents one of the largest development projects ever undertaken in the UK.[b] It underlies a separate oil field, Alba, which was discovered by Chevron in 1984 and which has been on stream since 1994. The field is operated by Britannia Operator, Ltd., an operating unit of Conoco and Chevron. Other partners in the project include ARCO, Saga Petroleum, Phillips, and Texaco. Recoverable reserves are estimated to be approximately 3 trillion cubic feet of gas and 145 million barrels of condensate and natural gas liquids. Indicative of the role of advanced technology in the field's development, approximately 25 percent of the field's reserves will be produced using subsea production facilities. Production from the field commenced in August 1998. The project has a capacity of 740 million cubic feet of gas per day, and over 50,000 barrels of condensate. The field was expected to cost $2.5 billion to develop; however, as a result of cost-saving efforts, costs are now expected to be approximately $2 billion.**

**Shearwater. This field is located approximately 120 miles east of Aberdeen and has an approximately 1,000 foot water depth. The producing reservoir is 15,000 feet below the seabed. The field was originally discovered in 1988 by ARCO but, in part due to the technical challenges of the field (the field is characterized by its high temperatures and pressures), the development decision was delayed until 1997.[c] The field is being developed using five high pressure/high temperature development wells. The wells are over three miles long and cost approximately $40 million each. Production is expected to commence in 2000 with a peak level production level of 400 million cubic feet and 75,000 barrels per day of gas and oil, respectively.**

**Ekofisk II. This project is located in the Norwegian Sector. As part of the project, Phillips, the operator, is phasing out or modifying 14 existing platforms.[d] The project involves the drilling of 45 new wells to replace 65 existing producing wells. About half of the wells drilled are horizontal, some of them extending up to four miles from the platform. While the project cost is estimated at about $2.5 billion, it is anticipated that it will extend the life of the field to the year 2050. The project has a productive capacity of 306,000 barrels per day of oil and 789 million cubic feet per day of natural gas. While production from the project commenced in 1998, production was lower**

**than anticipated due to start-up problems. Full production levels were reached by June 1999.**

**Schiehallion. This field is located offshore northern Scotland west of the Shetland islands and hence can not take advantage of the infrastructure available in the North Sea.[e] Instead, the oil is produced using a floating production, storage and offloading vessel. Estimated recoverable resources are 340 million barrels from the main field and an additional 85 million barrels from a shallower reservoir that overlies the main reservoir. Partners in the project include BP Amoco, Royal Dutch/Shell, Amerada Hess, Murphy Oil, and Statoil.**

**Peak production of 154,000 barrels of oil a day is expected. Production commenced in 1998 - just 27 months after government approval and less than five years after discovery. Indicative of the world class nature of the project, the first producing well had an initial production rate of 30,000 barrels a day.**

**As a result of the development of these and other projects, the many projections of declining production from the North Sea have proved to be premature. While production in 1998 was only marginally higher than in 1997, it was 57-percent higher than in 1990 (Figure 24). Other factors that have helped sustain production are:**

- **The application of new offshore technologies. Improvements in seismic technology, the use of floating production, storage, and offtake (FPSO) vessels, along with extended reach, horizontal, and multi-lateral drilling techniques have increased recovery rates which in turn have improved the economics of developing what were previously considered to be marginal prospects. For example, when regular oil production commenced from the Troll West oil province (a field in the Norwegian sector) the oil was produced from reservoirs that were approximately 75 feet thick. Now, extensive use of advanced drilling and production technology, including semisubmersible production units and horizontal well technology, has permitted the development of the oil in the Troll West gas province where the producing zones are less than 45 feet thick.[f]**
- **Reform of Fiscal Regimes. The UK, the largest North Sea producing country, eliminated royalty and petroleum revenue taxes on new fields in 1982 and 1993, respectively. For new projects, firms only need pay the normal corporation tax of 31 percent (the rate has since been reduced to 30 percent). While the fiscal regimes of Norway, Denmark, and the Netherlands continue to have profit tax rates as high as 70 percent, the tax and royalty component of the FRS companies' lifting costs has declined to $0.56 per barrel of oil equivalent in 1998 from $1.49 in 1990. As a result of this trend along with savings in direct lifting costs over the period, overall 1998 lifting costs for the FRS companies in the North Sea region averaged $4.84 per barrel, over 41 percent lower in real terms than in 1990.**

**Improved Utilization of Infrastructure. Many of the new fields are too small to justify development on a stand-alone basis. Nevertheless, development can be economic if the infrastructure costs can be spread out over several fields. A good example of this approach to project development is the Eastern Trough Area Project which is located approximately 145 miles east of Aberdeen in the Central North Sea near the UK/Norwegian median line.[g] This project is one of the largest North Sea developments in more than a decade. The cost of the project is $2.5 billion. The project represents an integrated development of four fields operated by BP Amoco and three by Royal**

**Dutch/Shell. Other participants in the project include Exxon, Murphy Oil, Total, and Mitsubishi Oil. At peak, production will average over 270,000 barrels of oil equivalent per day. Combined estimated recoverable from the project exceeds 500 million barrels of oil equivalent. Production commenced in late 1998.**

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**a EIA Form-28 does not break out drilling in the North Sea from total OECD drilling. However, the vast proportion of the drilling undertaken by the FRS companies in this region takes place in the North Sea.**

**b Offshore Technology, "Britannia," Net Resources International, London, UK.**

**c Offshore Technology, "Shearwater," Net Resources International, London, UK.**

**d Offshore Technology, "Ekofisk," Net Resources International, London, UK.**

**e BP Amoco, "Oil Production Starts from Schiehallion Field," (July 29, 1998).**

**f Offshore Technology, "Troll," Net Resources International, London, UK.**

**g BP Amoco, "ETAP 'Example of Major Benefits from North Sea Investment' - ETAP Fields Start Production," (July 30, 1998).**

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## *Special Topic:* The North Slope Challenge -- Can Production be Sustained?

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**Having produced almost ten billion barrels of oil to date, the Prudhoe Bay oil field remains the Nation's largest producing field with 1998 production averaging 693,000 barrels per day.[a] However, despite large investments in enhanced oil recovery by the operators in the late 1980's and early 1990's, production from the field is declining at around 10 percent per year, with 1998 production over 50 percent lower than in its peak year of 1987.**

**To slow the decline, ARCO, BP Amoco, Exxon, and the other owners of the field are investing $150 million in the Prudhoe Bay Miscible Injectant Expansion (MIX) project.[b] This project is designed to add 50 million gross barrels of petroleum liquids to ultimate field recovery and boost 1999 production by 20,000 barrels per day. To date, the development of other fields on the North Slope has only slowed the decline in the overall rate of production from the North Slope (Figure 25). Should the decline continue, a point will eventually be reached where it will be uneconomic to operate the Trans-Alaska Pipeline.**

**Yet, the potential is there to slow or even just perhaps reverse the decline. BP Amoco and the other Prudhoe Bay owners are considering developing "satellite pools" that lie above the main Prudhoe reservoir. It is believed that this could add several hundred million barrels of recoverable reserves to the field. In addition, the operators have identified 50 to 60 small-to-medium nearby prospects that could be developed at relatively low cost given that they would largely utilize existing infrastructure.**

**One of these fields is the Midnight Sun oil field just adjacent to Prudhoe Bay. This field commenced production in late 1998 with production of 2,000 barrels per day from the initial**

**discovery well.[c] Another North Slope field that commenced production in 1998 is the Tarn oil field. This 50-million barrel field is expected to reach peak production of more than 30,000 barrels per day by late 1999.[d] Partners in the field include ARCO (55.29 percent), BP America (39.28 percent), Unocal (4.95 percent), Mobil (0.36 percent), and Chevron (0.108 percent). While tiny by North Slope standards, the field is expected to rank among the top 30 producing domestic oil fields.**

**A field that remained under development as of the end of 1998 is the Alpine field.[e] Partners in this field are ARCO (78 percent) and Anadarko (22 percent). To minimize the field's environmental impact, the field's surface development will involve less than 100 acres, about two-tenths of one percent of the 40,000-acre field. Moreover, the field is being developed without the use of permanent roads. During the winter, temporary ice roads are being used to move drilling rigs and construction equipment; during the rest of the year access to the site is by air. In 1998 an exploration well and two development wells were drilled. Based on these and other developments, the field's reserve estimate has been increased by almost 20 percent to 429 million barrels. Peak production of 70,000 barrels per day is expected. In part because of the extensive use of horizontal wells and enhanced oil techniques, the field is expected to cost over $1 billion to develop. ARCO's share of the cost is expected to amount to over half of its 1999 capital budget.**

**Another high profile North Slope field is the Northstar project which, if developed, would be located on Seal Island, a man-made gravel island about 6 miles offshore from the North Slope shoreline.[f] The field was discovered in 1982 but development plans were shelved after the price of oil declined in the mid-1980s. The project was revived after it obtained royalty relief from the Alaskan State government in 1996. The project was slated to commence development work under BP Amoco (98 percent) and Murphy Oil (2 percent) but has been deferred due to the 1998 oil price decline.**

**Another project viewed as critical to slowing the decline in North Slope production is the Liberty field. This field has estimated recoverable reserves of 120 million barrels.[g] Liberty is located northeast of Prudhoe Bay, about five miles offshore. Development of the field has also been deferred for at least one year due to the price environment but the Environmental Impact Statement and other permitting efforts are continuing.**

**The Arctic National Wildlife Refuge (ANWR) is one of the North Slope's most prospective onshore areas, but is currently off limits to drilling. According to the U.S. Geological Survey, the area could contain a Prudhoe Bay-size field. Indicative of its potential, BP Amoco and Chevron have indicated to the State of Alaska that they believe that their Sourdough prospect, which borders ANWR, contains approximately 100 million barrels of recoverable oil.[h]**

**The National Petroleum Reserve (which lies to the west of Prudhoe Bay) also offers potential for significant new discoveries, with the mean estimated resources of the region exceeding 3 billion barrels. In 1998, the Department of Interior announced a plan under which 87 percent of the 4.6-million-acre northeast quadrant of the reserve would be available for leasing, with the remainder being held off-limits due to environmental concerns.[i] A lease sale was conducted in May 1999. Six companies (BP Amoco, Anadarko Petroleum, Chevron, Phillips Petroleum, ARCO, and R3 Exploration Corp.) submitted 174 bids on 133 tracts. Indicative of the poor quality of most of the tracts offered, only $100 million in winning bids were submitted.[j]**

**A considerable fraction of the remaining oil on the North Slope is viscous or "heavy." Accordingly, the long run future of the industry on the North Slope is somewhat dependent on the economics of producing this oil. On this score, the year 1998 opened a degree of optimism in that production was started up from West Sak, one of the largest heavy oil fields in the world.[k] This field overlies much of Kaparuk field, which is just west of Prudhoe Bay. The field has been estimated to contain more than 15 billion barrels of oil in place. Owners of the field include ARCO (55 percent), BP Amoco (39 percent), and Unocal (5 percent). Mobil and Chevron also own a combined 1-percent share of this field. Under Phase I of the development project, 50 wells were scheduled to be drilled by the end of 1998 with production reaching 7,000 barrels per day by early 1999. Full development of the West Sak core area is expected to require more than 500 additional wells and yield additional production of 62,000 barrels of oil per day. Because the project makes use of existing infrastructure from the Kaparuk field, development costs were expected to be only $2 per barrel. Despite this cost advantage, with the average annual welllhead price for North Slope crude in 1998 being $8.49, over six dollars less than in 1997, the project was subsequently placed on hold.[l]**

**The year 1998 also saw the startup of the Badami field, which is located 35 miles east of Prudhoe Bay.[m] This field is estimated to have recoverable reserves of around 120 million barrels of crude oil, making it the ninth-largest field on the North Slope. Peak production from the field was expected to be 35,000 barrels per day. Unfortunately, production was substantially lower than expected and the field was temporarily shut in.**

**The recent proposed merger between BP Amoco and ARCO, if approved by regulators, could have enormous implications for North Slope operations in that the merged company would account for 70 percent of Alaskan production. At a minimum, the merged entity would have to sell off around 350,000 acres of exploration acreage because of an Alaskan law that places an upper limit of 500,000 acres on any one company.[n] In terms of costs, the streamlining of operations in Alaska associated with the merger are expected by the companies to save $200 million. The merger could also be a catalyst for the development of the over 26 trillion cubic feet of natural gas that lie just above the oil cap at Prudhoe Bay.[o] Production of this gas has been stymied by several factors. First, there is the high cost of transporting the gas to market. Second, while ARCO has the largest share of the ownership rights to the gas, BP Amoco has the largest ownership share of the existing production infrastructure under the oil production agreement.[p] BP Amoco has indicated that if the merger with ARCO is approved, it plans on investing $5 billion in Alaska over the next five years, an increase over what the two companies had planned to invest separately. BP Amoco has also indicated that it will continue to advance ARCO's liquefied natural gas (LNG) feasibility study. Under one variant of this plan, the gas would be piped from the North Slope to Valdez in a pipeline that would parallel the existing oil pipeline. The gas would be converted into LNG in Valdez and exported to Asia. BP Amoco has also announced that it plans on building a $70 million gas-to-liquids plant near the North Slope that would test the technology of converting the natural gas into a liquid on the North Slope that could then be transported south using the existing pipeline.[q]**

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**a Division of Oil and Gas, Alaskan Department of Natural Resources.**

**b ARCO, Prudhoe Bay Owners to Build Large Oil Field Production Module in Alaska" (April 28, 1998).**

c ARCO, "First Prudhoe Bay Satellite Oil Field Starts Production," (October 5, 1998).

d ARCO, "Production Started from New Oil Field on Alaska's North Slope," (August 24, 1998).

e ARCO, "ARCO, Anadarko Increase Reserve and Production Estimates for Alpine Oil Field on Alaska's North Slope," (August 26, 1999).

f BP Amoco, Oilfield planned developments "Northstar."

g BP Amoco, Oilfield planned developments "Liberty."

h Division of Oil and Gas, Alaskan Department of Natural Resources.

i "http://www.blm.gov/nhp/news/press/pr980806.html,"

j "http://www.ak.blm.gov/affairs/press/990505.html,"

k ARCO, "http://www.ARCO.com/news/1997/co1231.html," (December 31, 1997).

l Energy Information Administration, *Petroleum Marketing Monthly,* Table 21.

m BP Amoco, Oilfield planned developments "http://www.bpamoco.com/alaska/bpamoco/oilfields/badami.htm,"

n Alexander Woostmänn, "http://www.gasandoil.com/goc/company/Cnn91854.htm," *Alexander's Oil and Gas Connections*, Volume 4, Number 17 (October 8, 1999).

o This gas had been classified as proved reserves until the mid-1980s at which point the gas was considered uneconomic due to its lack of marketability.

p Specifically, the ownership shares for the top three owners of the oil rim are as follows: BP (51 percent), ARCO (21.8 percent), Exxon (21.8 percent). For the gas rim, which lies just above the oil rim, the shares are: ARCO (41.56 percent) Exxon (42.56 percent) , and BP (13.84 percent). Source: Division of Oil and Gas, Alaskan Department of Natural Resources.

q ARCO, "http://www.ARCO.com/Corporate/news/1999/bp0401.html," (April 1, 1999).

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## *Special Topic*: Canada -- A New Era for Exploration and Development

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Historically, the Canadian oil and gas industry has been largely represented by independent producers in Alberta who drilled for conventional oil and natural gas. However, recent events, such as a number of mergers and acquisitions, and increased interest in offshore exploration and development (E&D) and oil from tar sands projects may soon alter this depiction of the industry.

### Mergers and Acquisitions Increase

**As a result of the decline in prices in 1998, exploration and development spending in Canada declined 27 percent from its 1997 level to $9.0 billion, although the FRS companies' Canadian expenditures were up 20 percent. In contrast, the value of mergers and acquisitions, accounted for largely by the acquisition of Canadian companies by U.S. firms, increased 25 percent to $13.8 billion, of which the FRS companies accounted for $7.3 billion, or almost three times the value in 1995.[a] Factors accounting for the increase included the weak Canadian dollar, the battered share prices of the Canadian firms, the increased interconnectedness of the North American natural gas market, and the relatively low cost of finding gas reserves in Western Canada. If sustained, this pace of mergers and acquisitions will clearly affect the industry's structure and, in turn, the industry's operations. In addition, the proposed merger between Exxon and Mobil by itself has the potential to significantly affect operations in Canada. Exxon owns 69 percent of Imperial Oil, one of Canada's largest producers, while Mobil is a partner in many large projects, including Hibernia, Sable Island, and Terra Nova as well as two of the largest oil sands projects in Northern Alberta.**

## Emphasis Shifts to Offshore

**The year 1998 was the Hibernia project's first full year of production. Production from the field averaged 64,800 barrels per day during 1998. The field was discovered in 1979 in the Jeanne d'Arc Basin on the Grand Banks of Newfoundland, 195 miles east southeast of St. Johns, in approximately 250 feet of water.[b] Given current technology, between 750 million and 1 billion barrels of light, low-sulfur oil are believed to be recoverable. The project was developed by a consortium of six companies: Mobil (33 percent ownership), Chevron (27 percent), Petro-Canada (20 percent), Canada Hibernia Holding Corp. (8.5 percent), Murphy Atlantic Offshore Oil Co. (6.5 percent), and Norsk Hydro (5 percent). The Canadian government owns 8.5 percent. Including subsidies from the Canadian government, the project cost over $7.0 billion to develop. The project was so costly to complete because of the need for the production platform to withstand the impact of an iceberg; the structure is strong enough to withstand a collision with a one-million ton iceberg. With expected additional investments, peak production is expected to reach 180,000 barrels per day. Operating costs during the first year were approximately $3.20 per barrel.**

**The Hibernia project is the first of what is generally expected to become a sustained pattern of offshore development. Another project undergoing development is Terra Nova, located about 22 miles east of Hibernia. Partners in the project include Petro-Canada, Mobil, Husky Oil, Murphy Oil, and Mosbacher Operating Ltd. The field is estimated to contain 300 to 400 million barrels of recoverable oil reserves,[c] with production of 100,000 barrels per day of low sulfur oil and 75 million cubic feet per day of gas beginning in 2001. Total development costs over the lifetime of the project could total $4 billion. Another field planned for development is Whiterose. If these projects proceed as expected, production off Newfoundland's Grand Banks could reach about 400,000 barrels per day by 2004.**

**Other offshore projects under development include the Sable Island project off Nova Scotia. This $3-billion project is expected to yield approximately 3 trillion cubic feet of natural gas that will be sent via pipeline to Canada's Atlantic provinces as well as to New England. The first phase of the project is expected to be completed by the end of 1999 with the initial production level being 500 million cubic feet of natural gas per day. The second phase includes developing three nearby gas fields. Additional development phases are expected given that Mobil, one of the partners in the**

project, has indicated that it has identified about 11 additional gas fields in the general area.

## Unconventional Oil Remains in Background

Canada's unconventional oil resource potential is enormous: there are believed to be up to 300 billion barrels of oil sands that are economic to exploit given current technology and prices. While this source of supply has tended to be viewed as costly and thus only marginally profitable, subsidies and improvements in technology have contributed to a 43-percent increase in production over the period 1994 to 1998, to 570,000 barrels per day.[d] Roughly half of this production is synthetic crude oil produced from mining operations. The remainder is sold directly to the marketplace as bitumen. Indicative of a new optimism over this supply source, over $24 billion in new projects are planned over the next decade. However, the low prices experienced in 1998 caused Petro-Canada to put off its approval of a 20,000-barrels-per-day oil sands plant in northern Alberta until 1999. Nevertheless, Syncrude Canada's $1.9-billion expansion program was still on track as of the end of 1998.

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a This figure excludes the proposed merger between Mobil and Exxon. Source: Sayer Securities Ltd. These data were converted to their U.S. dollar equivalent using the average annual exchange rate.

b Offshore Technology, Hibernia Net Resources International, London, UK.

c Offshore Technology, Sable Net Resources International, London, UK.

d National Energy Board of Canada: *1998 Annual Report*, Table 3.

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| Table 21<br>Entrant FRS Companies and Primary Line of Business, 1998 | | |
|---|---|---|
| **Company** | **Primary Energy Line of Business** | **Secondary Energy Line of Business** |
| Citgo Petroleum Corporation | Petroleum Refining | — |
| Clark Refining and Marketing, Inc., | Petroleum Refining | Gasoline service stations |
| Equilon Enterprises LLC [a] | Petroleum Refining | Gasoline service stations |
| Lyondell-Citgo Refining LP [b] | Petroleum Refining | — |
| Motiva Enterprises LLC [c] | Petroleum Refining | Gasoline service stations |
| Sunoco, Inc. | Petroleum Refining | Gasoline service stations |
| Tesoro Petroleum Corporation | Petroleum Refining | Petroleum products |
| Tosco Corporation | Petroleum Refining | Gasoline service stations |
| Ultramar Diamond Shamrock Corporation | Petroleum Refining | Gasoline service stations |
| Valero Energy Corporation | Petroleum Refining | Petroleum bulk stations and terminals |
| Williams Companies, Inc., | Natural gas transmission | NGL production |

[a] The parent companies of the Equilon Enterprises LLC joint venture are Shell Oil Company and Texaco, Inc.,.

[b] The parent companies of the Lyondell-Citgo Refining LP joint venture are Lyondell Chemical Company and Citgo Petroleum Corporation.

[c] The parent companies of the Motiva Enterprises LLC joint venture are Shell Oil Company; Texaco, Inc.; and Saudi Aramco.

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

| Table 22<br>Refining Capacity, by FRS Company Group, 1998 | | |
|---|---|---|
| | Share of Total | |
| | Incumbent [a] FRS Companies | Entrant FRS Companies |
| Refining Capacity | | |
| United States | 63.7% | 97.7% |
| Foreign | 36.3% | 2.3% |
| Total | 100.0% | 100.0% |
| [a] Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998. | | |
| Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). | | |

*Last Updated on 12/2/99*

**Table 23**
**Sources and Uses of Cash for FRS Companies, 1993-1997 (Average), and 1998**
(Percent)

| | 1993-1997 Incumbent [a] FRS Average Share of Total | 1998 Share of Total | |
|---|---|---|---|
| | | Incumbent [a] FRS Companies | Entrant FRS Companies |
| **Main Sources of Cash** | | | |
| Cash Flow from Operations | 67.4 | 58.7 | 33.1 |
| Proceeds from Long-term Debt | 18.8 | 17.8 | 56.6 |
| Proceeds from Disposals of Assets | 11.2 | 14.8 | 7.3 |
| Proceeds from Equity Security Offerings | 2.6 | 8.6 | 3.0 |
| | 100.0 | 100.0 | 100.0 |
| **Main Uses of Cash** | | | |
| Additions to Investment in Place | 55.9 | 60.6 | 51.5 |
| Reductions in Long-term Debt | 21.5 | 15.3 | 27.2 |
| Dividends to Shareholders | 17.8 | 17.3 | 18.2 |
| Purchase of Treasury Stock | 4.9 | 6.8 | 3.0 |
| | 100.0 | 100.0 | 100.0 |

[a] Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

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

*Last Updated on 12/2/99*

| Table 24. U.S. Refined Product Price, Margins, and Costs, by FRS Company Group, 1998 | | | | |
|---|---|---|---|---|
| | Dollars per Barrel | | Category as a Percent of the Average Product Price | |
| | Incumbent [a] FRS Companies | Entrant FRS Companies | Incumbent [a] FRS Companies | Entrant FRS Companies |
| FRS Refined Product Margin [b] | 1.53 | 1.65 | 7.5 | 8.3 |
| Marketing Costs | 1.68 | 1.04 | 8.2 | 5.3 |
| Energy Costs | 0.75 | 0.70 | 3.7 | 3.5 |
| Other Operating Expense | 2.47 | 2.28 | 12.1 | 11.5 |
| Gross Margin[c] | 6.42 | 5.67 | 31.5 | 28.6 |
| Average Petroleum Product Price | 20.36 | 19.84 | 100.0 | 100.0 |

[a]Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.

[b]Computed from unrounded data.

[c]Refined product revenues less raw material and product purchases divided by refined product sales volume.

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

*Last Updated on 12/15/99*

## Table 25
## Gasoline Distribution by FRS Company Group, 1998
(percent)

| Distribution Category | Share of Total | |
|---|---|---|
| | Incumbent[a] FRS Firms | Entrant FRS Firms |
| Sales Volume | | |
| Wholesale Volume | 50.1 | 63.5 |
| Retail Volume | | |
| Dealer Volume | 24.4 | 14.0 |
| Company-Operated Volume | 15.1 | 14.1 |
| Direct Volume | 9.6 | 5.5 |
| Intersegment Volume | 0.9 | 3.1 |
| Total Volume | 100.0 | 100.0 |
| Average Monthly Volume | (thousands of gallons) | |
| Dealer Outlets | 90.1 | 55.0 |
| Company-Operated Outlets | 142.3 | 144.0 |
| Total Retail Outlets | 104.8 | 79.7 |

[a] Incumbent FRS firms were respondents to Form EIA-28 in both 1997 and 1998.

Note: Percentages were calculated from unrounded data.

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

**Table 26.**
**Finding Costs by Region for FRS Companies, 1995-1997 and 1996-1998**
(Dollars per Barrel of Oil Equivalent)

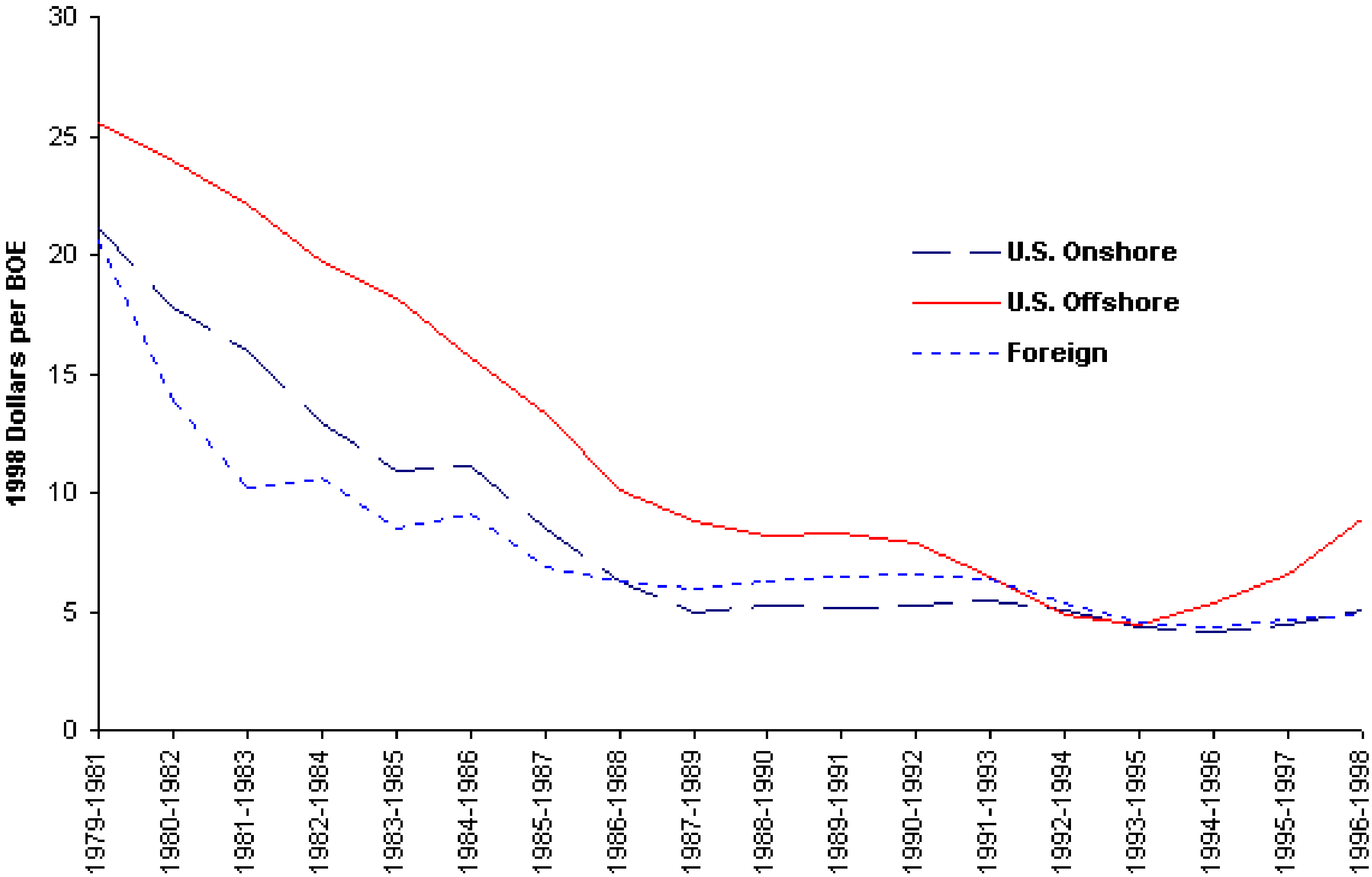
| Region | 1995-1997 | 1996-1998 | Percent Change |
|---|---|---|---|
| **United States** | | | |
| Onshore | 4.10 | 5.26 | 28.1 |
| Offshore | 6.37 | 8.83 | 38.8 |
| Total United States | 4.88 | 6.47 | 32.8 |
| **Foreign** | | | |
| Canada | 6.88 | 7.76 | 12.7 |
| OECD Europe | 5.49 | 7.49 | 36.4 |
| Former Soviet Union | 5.22 | 8.34 | 59.8 |
| Africa | 4.26 | 3.76 | -11.7 |
| Middle East | 2.20 | 2.71 | 23.0 |
| Other Eastern Hemisphere | 4.66 | 4.55 | -2.4 |
| Other Western Hemisphere | 2.32 | 2.34 | 0.9 |
| Total Foreign | 4.51 | 4.81 | 6.7 |
| | | | |
| **Worldwide** | 4.68 | 5.54 | 18.3 |

Note: The above figures are 3-year weighted averages of exploration and development expenditures (current dollars), excluding expenditures for proven acreage, divided by reserve additions, excluding net purchases of reserves. 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).

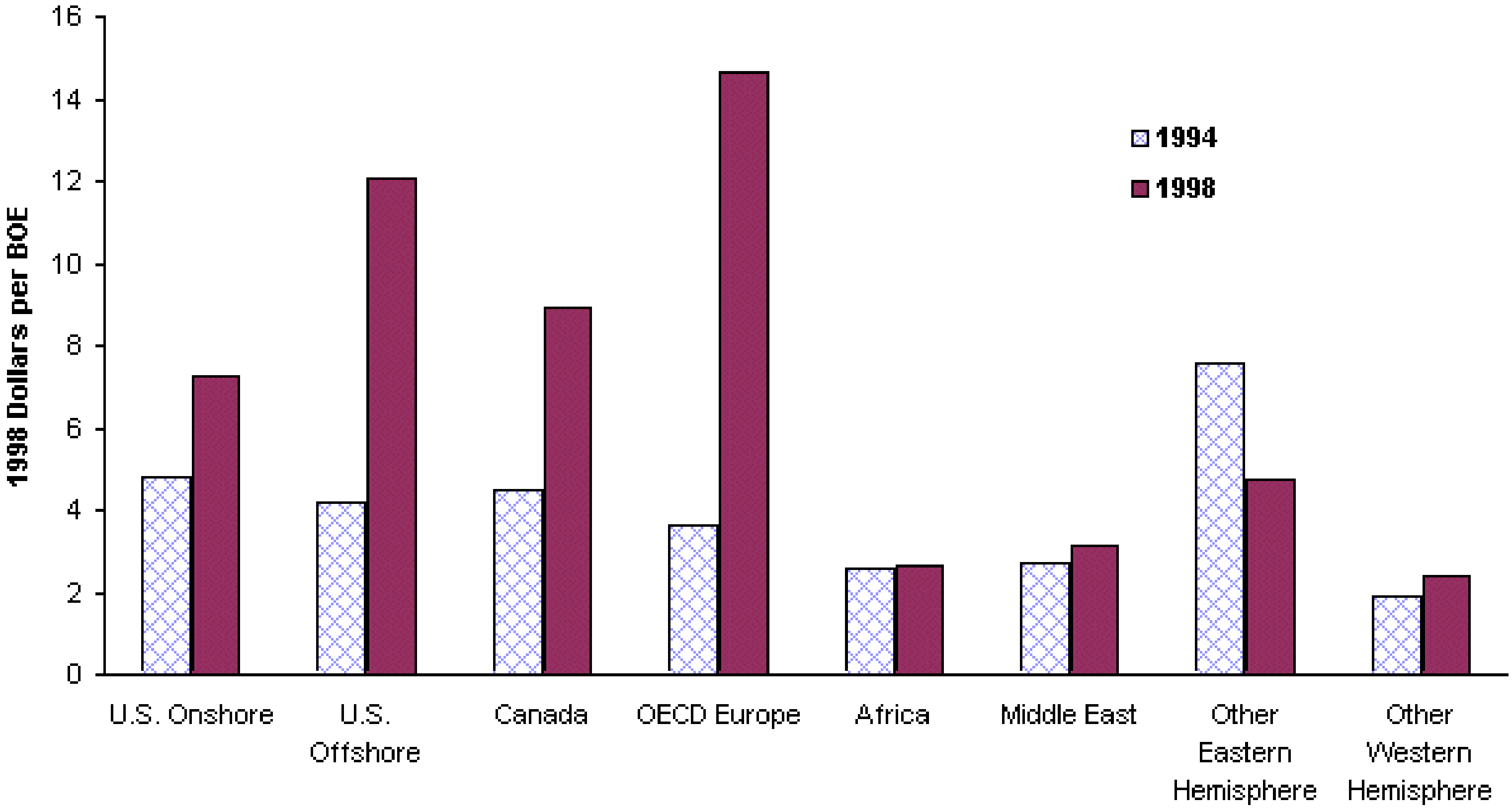
*Last Updated on 12/9/99*

**Figure 21. U.S. Onshore, U.S. Offshore, and Foreign Finding Costs (Three-Year Moving Average) for FRS Companies, 1979-1981 to 1996-1998**




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

**Figure 22. Annual Finding Costs for FRS Companies, 1994 and 1998**




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

## Table 27.
## Analysis of Increase in Annual Finding Costs for FRS Companies in Selected Regions and Worldwide, 1994-1998

| | U.S. Onshore | U.S. Offshore | Canada | OECD Europe | World-wide |
|---|---|---|---|---|---|
| Annual Finding Costs ($1998 per BOE) | | | | | |
| 1994 | 4.78 | 4.20 | 4.48 | 3.61 | 4.19 |
| 1998 | 7.26 | 12.07 | 8.95 | 14.65 | 6.63 |
| | | | | | |
| Share of Change in Finding Costs due to:[a] | (percent) | | | | |
| Lower finding rate | 35 | 28 | 84 | 93 | 19 |
| Increased expenditures per well | 65 | 72 | 16 | 7 | 81 |
| | | | | | |
| Share of Increased Expenditures | | | | | |
| per Well due to: | | | | | |
| Increased drilling costs | 32 | 44 | NA | NA | 36 |
| Increase in other costs | 68 | 56 | NA | NA | 64 |

[a]Shares based on percent changes in inverse of finding rates and expenditures per well.

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 (excluding net purchases of reserves) per well completed. NA = not available. Other costs include unproven acreage acquisitions, exploration expenses, lease equipment, support equipment, work-in-progress, and direct overhead.

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

*Last Updated on 12/15/99*

**Table 28.**
**Oil and Gas Reserves and Production for FRS Companies, 1997-1998**

| | U.S. Onshore | | U.S. Offshore | | Foreign | | Worldwide | |
|---|---|---|---|---|---|---|---|---|
| **Reserves and Production** | 1997 | 1998 | 1997 | 1998 | 1997 | 1998 | 1997 | 1998 |
| Oil (million barrels) | | | | | | | | |
| Reserve Additions | 1,326 | 489 | 717 | 352 | 2,064 | 2,378 | 4,107 | 3,219 |
| Net Purchases | -1,301 | 179 | -107 | 80 | -180 | 894 | (1,588) | 1,153 |
| Production | 1,096 | 991 | 363 | 397 | 1,473 | 1,546 | 2,932 | 2,935 |
| Total Oil Reserves | 12,386 | 12,063 | 3,319 | 3,354 | 13,839 | 15,391 | 29,544 | 30,808 |
| | | | | | | | | |
| Oil Reserve Additions[a] / Production (percent) | 121 | 49 | 198 | 89 | 140 | 154 | 140 | 110 |
| | | | | | | | | |
| Natural Gas (billion cubic feet) | | | | | | | | |
| Reserve Additions | 4,997 | 5,808 | 2,594 | 2,588 | 7,553 | 7,542 | 15,144 | 15,937 |
| Net Purchases | -3,036 | 225 | -437 | 935 | 285 | 3,322 | (3,189) | 4,481 |
| Production | 5,450 | 5,493 | 2,849 | 2,903 | 4,859 | 5,182 | 13,158 | 13,578 |
| Total Gas Reserves | 53,825 | 55,111 | 19,769 | 20,389 | 63,347 | 69,350 | 136,941 | 144,849 |
| | | | | | | | | |
| Gas Reserve Additions[a] / Production (percent) | 92 | 106 | 91 | 89 | 155 | 146 | 115 | 117 |

[a]Excludes purchases and sales of reserves.

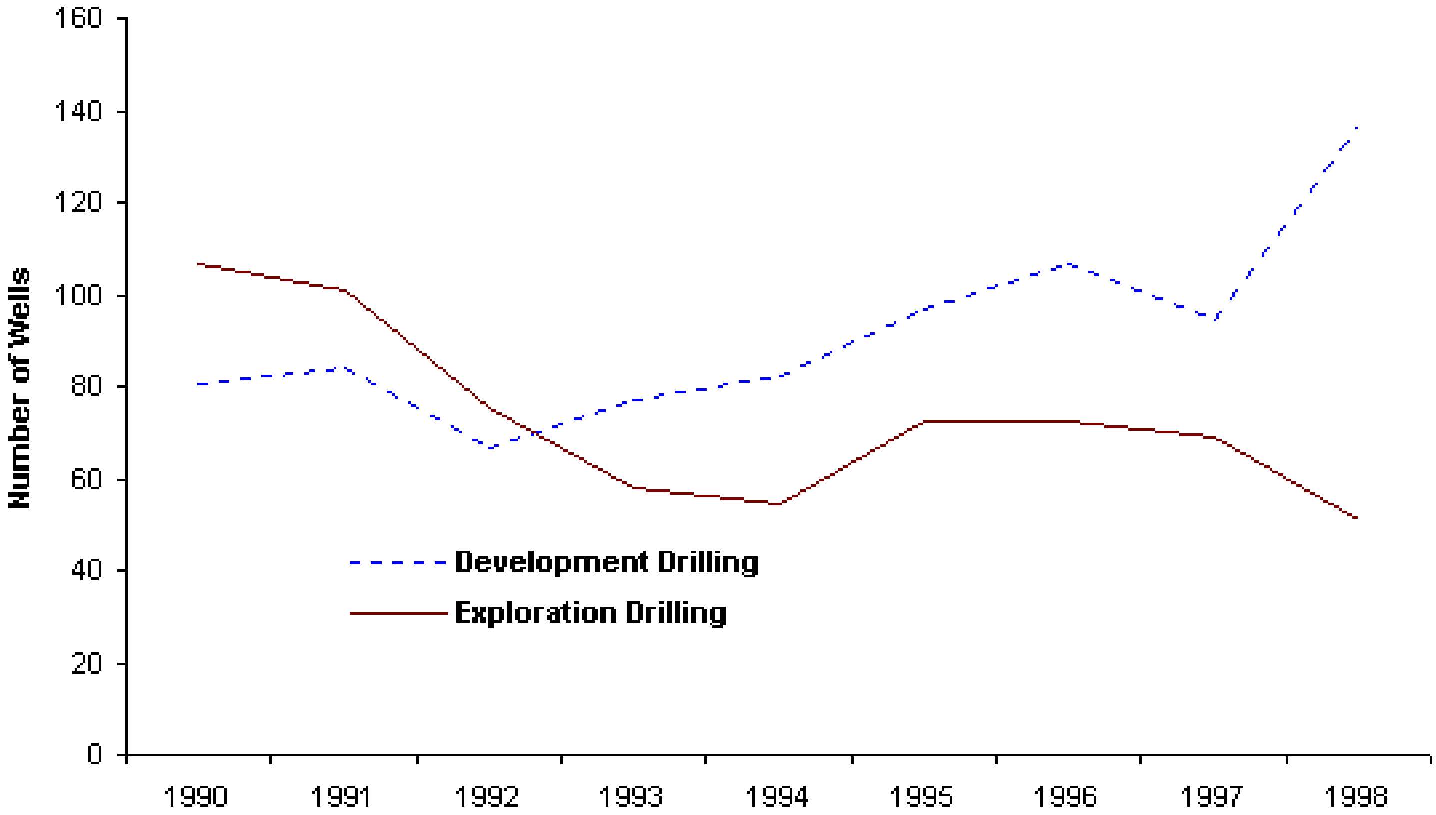
Note: Sum of components may not equal totals due to independent rounding.

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

*Last Updated on 12/15/99*

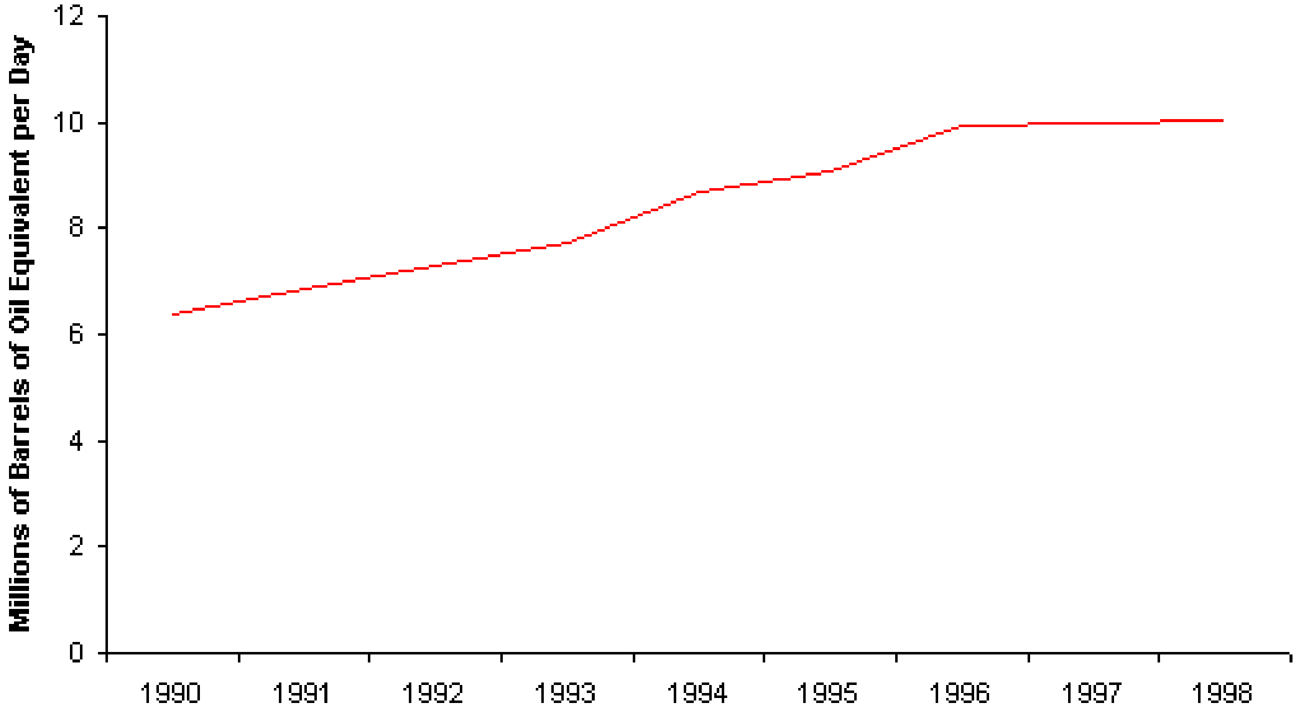
**Selected Oil Infrastructure in the Caspian Sea Region**

**Figure 23. Drilling by FRS Companies in OECD Europe, 1990-1998**



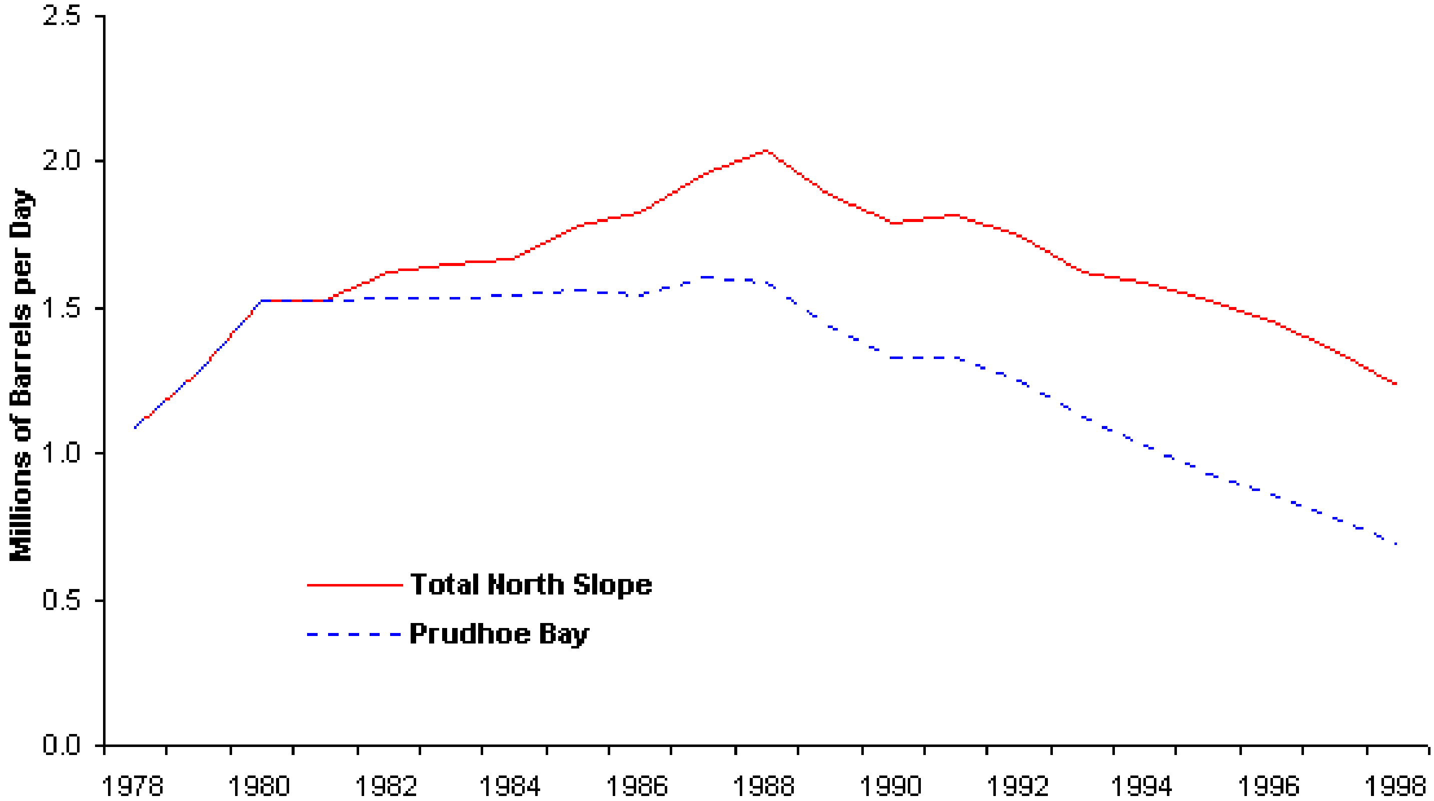

Source: Energy Information Administration, Form-28 (Financial Reporting System).

**Figure 24. North Sea Oil and Gas Production, 1990-1998**




Source: "North Sea Survey: The Oil Price Factor Kicks In," *Petroleum Economist*, April 21, 1999. Natural Gas converted to its oil equivalent using the conversion factor of 0.178 barrels of oil per thousand cubic feet of gas.

Figure 25. Alaskan North Slope and Prudhoe Bay Oil Production, 1978-1998




Note: Data for 1998 are preliminary.
Source: Alaskan Department of Natural Resources.

# 5. Foreign Direct Investment in U.S. Energy in 1997

This report presents an analysis of foreign direct investment in U.S. energy resources, assets, and companies.[Note 89] It describes the role of direct foreign ownership in U.S. energy enterprises with respect to acquisitions and divestitures, capital investment, energy operations, and financial performance. Additionally, since energy investments are made in a global context, the report examines patterns of direct investment in foreign energy enterprises by U.S.-based companies.

"Foreign direct investment" (FDI) is the ownership of 10 percent or more of the voting securities, or the equivalent, of a U.S. business enterprise by a foreign entity.[Note 90] FDI is widely used as a measure of the control of foreign investors over the management and disposition of U.S. assets.[Note 91] "U.S. affiliates" and "foreign-affiliated" companies are defined as U.S. business enterprises in which a foreign entity holds an ownership interest of 10 percent or more. "FDI-related" transactions are transactions directly or indirectly made by foreign investors (with respect to U.S. business enterprises or assets) in which a foreign entity at some point in the transaction holds an ownership interest of 10 percent or more. However, it should be noted that holding 10 percent or more of a company often may, but does not necessarily, constitute control of that company. The determination of control is a complex and often subjective process in which many factors in addition to the percentage of ownership must be considered.

## Foreign Acquisitions and Divestitures of U.S. Energy Assets

### Foreign Acquisitions Rebound

FDI-related acquisitions of companies or assets in the U.S. energy sector increased to $3.3 billion in 1997 (Table 29).[Note 92] This continues a pattern, begun in 1989, of foreign acquisition levels fluctuating between $1 billion and $5 billion. The range of year-to-year oscillations has been smaller in the 1990’s than in the 1980’s (Figure 26). There are several factors that may have contributed to the increase in 1997. One is that the overall merger and acquisition activity in the United States was at a record high that year, and this level is likely to be indicative of the level of FDI-related transactions as well. Another is that strong earnings by foreign companies and their U.S. affiliates provided funds to finance the increased merger and acquisition activity in the United States. Additionally, continued deregulation and reorganization in the U.S. electric power industry afforded more opportunities for FDI in that industry.

Some of the more notable developments in FDI-related acquisitions and divestitures of U.S. energy assets in 1997 were:

- The largest acquisition was of electric power generation assets. This is the first large FDI-related acquisition in the electric power sector ever identified in this report.
- Acquisitions of upstream oil and gas assets, led by the exit of a domestic integrated petroleum company from upstream activities, rebounded to $1.3 billion, somewhat above their recent average. These acquisitions were primarily for natural gas assets.
- Acquisitions of midstream natural gas assets (i.e., transportation, processing, and marketing) fell to their lowest level of the last four years.
- Coal asset acquisitions remained small in value, as they were in the two prior years.
- Divestitures of U.S. energy assets by foreign investors were led by one large downstream

petroleum transaction. Downstream assets were also the largest category of divestitures in 1996.

- Divestitures of electric power assets were substantial because many of the assets (mainly international) acquired in the largest FDI-related acquisition in 1997 were immediately sold to a U.S. company.

### Electric Power Is Put Into Play

The largest FDI-related acquisition in the energy sector in 1997 was in the electric power industry. NGC (now Dynegy) purchased Destec Energy, a developer and manager of electric power generation facilities, for $1.3 billion.[Note 93] This transaction is in part a consequence of the deregulation and restructuring of the electric power industry that is ongoing in the United States.[Note 94] Notably, this first major foreign acquisition of electric power assets was of the newest type of player in electric power generation, an independent power producer, not of a traditional electric utility.[Note 95]

NGC has been a major player in foreign investment activity in the United States since 1994. It is a textbook illustration of several recent trends in North American energy markets, the integration of the Canadian and U.S. natural gas markets, the tendency toward vertical integration of enterprises in the natural gas industry, and the integration and deregulation of natural gas and electricity markets.[Note 96] At the beginning of 1994, NGC (then the largest independent natural gas marketing company in the United States) had already begun expanding into midstream natural gas assets and electricity trading. Later that year Nova (now Nova Chemical), then a Canadian energy and chemicals company, purchased part of NGC in the largest foreign petroleum and natural gas acquisition that year. British Gas (now BG) also acquired part of NGC that year. In 1995, NCG purchased Trident NGL, then North America’s largest natural gas liquids operator, in the fourth largest foreign acquisition that year. Trident’s electricity generation assets were part of that acquisition. NGC also purchased Ozark Gas Transmission System in 1995. In 1996, the largest foreign transaction was NGC’s purchase, from Chevron, of its natural gas marketing business and of Warren Petroleum, the largest U.S. marketer of natural gas liquids. As part of the transaction, Chevron acquired part ownership in NGC. By the end of 1996, British Gas, Chevron, and Nova were all major NGC shareholders.[Note 97]

NGC’s 1997 purchase of Destec from Dow Chemical and Destec’s other shareholders for $21.65 in cash for each share made electric power generation a major part of the company’s activities. Destec has experience in developing, constructing, managing, and operating power facilities worldwide and had interests in approximately 25 operating facilities at that time. After the transaction was completed, Destec became a wholly owned subsidiary of NGC.

The transaction was a complicated one, because NGC quickly disposed of some of Destec’s assets. The first was through an agreement with AES (a U.S. company that is one of the world's leading independent power producers), reached in part before the Destec purchase by NGC, for AES to purchase most of Destec’s international assets from NGC. The agreement was stipulated in a joint purchase proposal that NGC and AES together submitted to Destec. The purchase by AES of Destec’s international assets was consummated for $439 million. In addition, within a month after the closure of the Destec purchase, NGC made, or agreed to, two other major sales of Destec assets. One was closure on the sale of Destec’s share of the 212-megawatt gas-fired Tiger Bay cogeneration plant to Florida Power for $147 million; Tiger Bay had a long-term purchased power contract with Florida Power. The other was an agreement with an affiliate of Enron to sell to it certain lignite and oil and gas reserves owned by Destec for $149 million, while retaining various royalty interests, mineral interests, and easements for pipeline construction. Thus, the net purchase of Destec assets retained by NCG totaled $525 million.

## FDI in the U.S. Electric Power Industry

The electric power industry in the United States has historically experienced little FDI because of two Federal laws. One is the Public Utility Holding Company Act of 1935 (PUHCA), which restricts the ownership of public utilities, whether the owner is domestic or foreign. Legislative exemptions from PUHCA restrictions are the source of the restructuring that is currently ongoing in the U.S. electric power industry. The other is the Atomic Energy Act of 1954, which prohibits the licensing of nuclear facilities that are owned, controlled, or dominated by a foreign investor. The U.S. Nuclear Regulatory Commission (NRC) recently issued new license review guidelines that contain a less restrictive interpretation of this requirement.

### *The Genesis of Electric Power Industry Restructuring in the United States*

Although the causes of restructuring in U.S. electric power are many and debatable, relaxing some of the constraints on electric utility organizational structure imposed by PUHCA was clearly key to allowing the industry to restructure. PUHCA specifies that "any company which directly or indirectly owns, controls, or holds with power to vote, 10 percent … or more of the outstanding voting securities of a public utility" is a public utility holding company subject to its restrictions. The Act places all public utility holding companies in one of two categories. Holding companies in one category (registered) are limited to owning a "single integrated public-utility system" and, along with their subsidiaries, to engage only in businesses that are "incidental … or appropriate to the operation of" that system. Holding companies in the other category (exempt) in most cases must either "carry on their business [along with their subsidiaries] substantially in a single State" or be predominately an operating utility in one State and those contiguous to it. Thus, under PUHCA, public utility holding companies are restricted geographically to owning a single integrated utility system or to operating in at most one State plus those adjacent to it. In the former case, the holding company and its subsidiaries are also restricted to businesses that are directly related to the utility system's business.

Restructuring in U.S. electric power got its start with the Public Utility Regulatory Policies Act of 1978, which generally exempted from PUHCA electric power producers that used cogeneration or renewable resources technologies to produce electricity. The restructuring was broadened substantially by the Energy Policy Act of 1992, which created a new category of power producers called exempt wholesale generators. They are defined as entities that are "engaged … exclusively in the business of owning [and/] or operating … all or part of one or more … [facilities that are] used for the generation of electric energy exclusively for sale at wholesale." This category of electric power producers is exempt from PUHCA's regulations and can be owned even by utility holding companies. These two exemptions from PUHCA's restrictions, by placing fewer limitations on companies that own public utilities, facilitated much broader participation in the U.S. electric power industry and the rise of independent (nonutility) power producers.

### *Foreign Ownership of Nuclear Generating Assets*

The Atomic Energy Act of 1954 has long been interpreted as banning foreign investment in the nuclear generating facilities of the U.S. electric power industry.[Note 98] The Act precludes the issuance of a nuclear reactor license to "[a]ny corporation or other entity … [that] is owned, controlled or dominated by an alien, a foreign corporation, or a foreign government." However, NRC recently approved the transfer of the operating license for the undamaged reactor at Three Mile Island from GPU to AmerGen Energy, a joint venture of PECO Energy and British Energy, headquartered in Scotland.[Note 99] In doing so, NRC conditioned its approval of the sale on several provisions relating to foreign ownership. It required that at least half of AmerGen's management committee (which is to be named by its non-foreign owners) be U.S. citizens, that certain key management positions be U.S. citizens, and that it be notified of any filing of beneficial ownership of PECO stock with the U.S. Securities and Exchange Commission.[Note 100]

Less than two months before this decision, NRC had issued draft guidelines for determining foreign ownership, control, or domination.[Note 101] Citing a 1966 decision by its predecessor, the Atomic Energy Commission, the NRC argues that "[a]n applicant is considered to be foreign owned, controlled, or dominated whenever a foreign interest has the 'power,' direct or indirect, whether or not exercised, to direct or decide matters affecting the management or operations of the applicant." The guidelines conclude that "[a]n applicant that is partially owned by a foreign entity … may still be eligible for a license if certain conditions are imposed …."[Note 102]

The two exemptions to PUHCA and the extended definition by NRC have gone a long way toward allowing foreign companies to become players in the U.S. electric power industry, particularly the generation segment. Now foreign companies that own certain types of U.S. electric power assets need not be restricted to owning a single integrated utility system and to activities that are related to that system's business, nor to operating in one State plus those adjoining it, nor to operating only non-nuclear generating facilities. As evidence that these changes mean more FDI in U.S. electric power, and in the wake of the Destec purchase by NGC in 1997, several other U.S. electric power companies and nuclear generation facilities are in various stages of being acquired by foreign investors.

### U.S. Upstream Oil and Gas Assets Continue to be Attractive

Statoil, through its U.S. energy management subsidiary The Eastern Group (now Statoil Energy), purchased Blazer Energy, Ashland's domestic exploration and production company, for $566 million in cash in 1997. This was the largest foreign acquisition of petroleum and natural gas assets that year. Statoil is an integrated Norwegian petroleum company, owned by the State. It is the leading player on the Norwegian continental shelf, and has been gradually expanding its international upstream operations in recent years. One of the reasons given for the purchase was that it would provide Statoil with an entry into operating in the deeper waters of the Gulf of Mexico.[Note 103] Blazer's reserves were almost totally natural gas.[Note 104]

The second-largest foreign acquisition in 1997 was the acquisition of 100 percent of the common stock of American Exploration by Louis Dreyfus Natural Gas. The majority owner of the merged company is the Paris-based merchandiser, exporter, and investor, Louis Dreyfus et Cie. In the acquisition, Louis Dreyfus commented that in addition to obtaining American Exploration's reserve base (increasing Dreyfus' reserves by 22 percent), it also gained American Exploration's inventory of high potential exploratory prospects and its strong prospect generating and technical skills.[Note 105] American Exploration's reserves were about two-thirds natural gas. After the merger, Louis Dreyfus' reserves were split about 80 percent in natural gas and 20 percent in crude oil and liquids (on an equivalent basis). The reserves added by the acquisition extended Dreyfus' activities southeastward, into the Gulf of Mexico, South and East Texas, and Southwest Arkansas. Over the two years preceding the merger, American Exploration and Louis Dreyfus had worked together closely on several projects. Nonetheless, Louis Dreyfus recognized $75 million in impairment charges in 1997, substantially all of which was recorded in connection with the acquisition.

Several smaller foreign oil and gas acquisitions (see Table C1) were of drilling service companies, four of them by DI Industries (now Grey Wolf). DI Industries is a direct investment of Norex Industries (now Siem Industries), a Cayman Islands industrial holding company with investments in the oil and gas drilling services industry and the cruise industry. These four acquisitions totaled $203 million.

### Divestitures Dominated by Downstream Petroleum and Reselling of Electricity Assets

Ultramar Diamond Shamrock acquired Total Petroleum (North America), a petroleum refining and marketing company, from Total (Total Compagnie Francaise des Petroles, now TotalFina) of France for $852 million. Ultramar gained three refineries, with a combined throughput capacity of 147,000 barrels per day, 11 terminals, 2,100 retail outlets in the central United States (of which 560 were company-owned) and 1,100 miles of pipeline.[Note 106] In large part to finance the purchase, Ultramar issued $400 million of senior notes, and Total ended up owning 8 percent of Ultramar. Since this is below the 10-percent threshold for direct investment and Total Petroleum had been an FDI-related investment of Total's, the transaction was classified as a foreign divestiture. In 1995, the second- and third-largest foreign divestitures were also of refining and marketing assets, both to Tosco, the leading independent U.S. petroleum refining and marketing company.

The second-largest foreign energy divestiture in 1997 was the reselling of assets acquired when NGC (now Dynegy) purchased Destec. The assets included electric power generation facilities, located internationally and in the United States, and some lignite and oil and gas reserves. The discussion of NGC's acquisition of Destec, above, provides further details of this divestiture.

Hanson (United Kingdom) divested Peabody Coal to the newly created Energy Group (United Kingdom) in 1997. Because Peabody had been acquired by Hanson in 1990, it was already classified as foreign-affiliated, and, since this was a transaction between two foreign parent companies, it does not alter FDI in the United States.

## The Foreign Direct Investment Position

In the United States, the Bureau of Economic Analysis (part of the U.S. Department of Commerce) collects data regarding FDI from the U.S. affiliates of foreign investors. One comprehensive indicator of FDI maintained by the Bureau is the FDI position in the United States, measured as the book value of foreign investors' equity in, and net outstanding loans to, their U.S. affiliates.[Note 107] The FDI position encompasses more than FDI-related acquisitions and divestitures. It also includes reinvested retained earnings, net loans, and equity flows other than for FDI-related acquisitions or divestitures. Because of these differences, the FDI position gives a different picture of foreign investor activity in the United States from the FDI-related acquisitions and divestitures discussed in the previous section. For example, repayments of debt by U.S. affiliates could swamp increased FDI-related acquisitions by foreign investors, resulting in the FDI position decreasing while FDI-related acquisitions were increasing.

In addition to these definitional distinctions, there are several reasons why net FDI-related acquisitions and divestitures and the FDI position diverge. One is that the FDI position data usually assign the transaction to the industry of the foreign affiliate company.[Note 108] That industry is determined by the industry that accounts for the largest percentage of the affiliate's sales. This practice may result in some energy transactions being assigned to another industry. For example, a transaction involving the energy assets of an affiliate whose largest share of sales was in another industry would be classified in that other industry. Another is that the Bureau is obliged to aggregate its reported data to maintain its confidentiality. Some of the aggregation categories do not keep energy transactions separate from other transactions. For example, natural gas distribution and sanitary service utility investments are included in the same category as electric power investments in the published FDI position data. In addition, because data collected by the Bureau are kept confidential, individual transactions from other sources cannot be compared to the Bureau's data in order to correct any disparities.

## FDI Position in U.S. Economy Continues Strong Growth

The FDI position in the U.S. economy grew substantially in 1997 (Table 30), 15 percent over the 1996 level.[Note 109], [Note 110] Japan just about caught the United Kingdom in 1997 to become the country with the largest FDI position in the U.S. economy. While FDI-related acquisitions by Japanese investors declined substantially, capital contributions to existing affiliates, especially reinvested earnings, remained strong. For the United Kingdom, a decrease in U.S. affiliates' debt to their foreign parents and an increase in foreign parents' debt to their U.S. affiliates offset strong increases in net equity capital inflows and in reinvested earnings in the United States to moderate the growth of that country's FDI position. Large FDI positions were also held by the Netherlands and Germany, and, to a lesser extent, France and Switzerland, resulting in the FDI position of European parents accounting for about 60 percent of the total FDI position in the United States.

## Petroleum and Natural Gas Industry's FDI Position Grows Steadily

The FDI position in the U.S. petroleum and natural gas industry grew to $48 billion in 1997, its fourth-successive year of increase (Table 31). However, the amount of growth was less than half of that in 1996, when it was fueled by large increases in equity capital inflows, which did not materialize in 1997. Earnings for foreign-affiliated petroleum and natural gas companies in 1997 were somewhat above their high level in 1996, but reinvested earnings were down somewhat. As a result of the fall in equity capital inflows, petroleum and natural gas' share of the FDI position in the U.S. economy fell in 1997, as it has in almost every year since 1987. New FDI to acquire or establish businesses in the U.S. petroleum and natural gas industry was only $688 million in 1997.[Note 111]

The share of the FDI position in petroleum and natural gas by country continued to show major differences from the FDI position for other industries (Figure 27). Investors from the Netherlands, the United Kingdom, and Australia (the latter of which accounts for virtually all of the FDI position in U.S. petroleum and natural gas from the Asia and Pacific countries) invest relatively more in U.S. petroleum and natural gas than in all other industries, while other countries in Europe and, most especially, Japan take a much smaller relative FDI position in petroleum and natural gas. The Netherlands, the United Kingdom, and Australia are the three countries with the largest FDI positions in petroleum and natural gas (Table 32). Each of the three countries is home to a parent company linked to a major petroleum and natural gas subsidiary in the United States: Shell Oil, a subsidiary of Royal Dutch/Shell (the Netherlands and the United Kingdom); BP America, a subsidiary of British Petroleum (now BP Amoco) of the United Kingdom; and BHP Petroleum Americas, a subsidiary of Broken Hill Proprietary of Australia.

# Foreign-Affiliated Companies' Role in U.S. Petroleum, Natural Gas, and Coal Operations

The participation of U.S. affiliates of foreign investors in the U.S. fossil-fuel industries declined across the board in 1997, the first year that has happened since 1991 (Figure 28). Notably, the share of U.S. refinery capacity of foreign-affiliated companies declined for the fourth-straight year. It fell to 23 percent in 1997, its lowest level since 1987. The U.S. affiliates' share of coal production also declined in 1997, reversing a long-standing trend of greater participation in that industry. Their share of oil production in 1997 was essentially unchanged, and their share of natural gas production declined slightly; both have been slowly declining for almost 10 years.

## Decline in Foreign Affiliates' Share of Refining Capacity Accelerates

Foreign-affiliated firms reduced their commitment to U.S. petroleum refining again in 1997 (Table 33). Between 1993 and 1997, their share declined almost 7 percentage points, from 30 percent to 23 percent of refining capacity (Figure 28). The decline in 1997 is largely due to the exit of two foreign companies, Total (now TotalFina) (France) and TrizecHahn (Canada, operating through Clark USA), from U.S. refinery operations. Total reports that its U.S. refining and marketing operations were too small to remain competitive, so they were merged with Ultramar Diamond Shamrock.[Note 112] TrizecHahn, which itself was formed by a merger in 1996, reported that it wanted to become solely a real estate company.[Note 113] There was one FDI-related acquisition of refinery assets: Petroleos de Venezuela acquired Unocal's share of their refining and marketing joint venture, Uno-Ven. However, since Uno-Ven was already an FDI-related company, this acquisition caused no increase in FDI-related refinery capacity in the United States.

U.S. affiliates of foreign investors also withdrew from retail marketing in the United States. The total number of foreign-affiliated retail outlets in the United States apparently[Note 114] fell at a faster rate than the total number of U.S. retail outlets, decreasing the foreign-affiliate's share slightly (Table 34). Shell Oil and Citgo Petroleum had conspicuous increases in their number of outlets, while the decline in foreign-affiliated retail outlets stems largely from the exit of Total and TrizecHahn from downstream operations. However, the total amount of gasoline sales by foreign affiliates declined 7 percent in 1997, while total U.S. sales increased 1 percent.

## Foreign-Affiliated Companies' Share of Oil Production Increases

Total net production of crude oil and natural gas liquids in the United States by foreign-affiliated companies increased slightly in 1997 (Table 35). Only BP America had a substantial decline (falling by more than 9 thousand barrels per day), while Shell Oil accounted for the bulk of production increases. With U.S. total production essentially flat, the share of foreign affiliates in U.S. production increased more than one-half of a percentage point. Total net production of dry natural gas by foreign-affiliated companies appeared[Note 115] stable in 1997. While Shell Oil, and, to a lesser extent, BHP Petroleum had notable declines in production, it was more than made up for by increases from Forcenergy, Canadian Occidental, and Fina.

Since total U.S. reserves of crude oil and natural gas liquids increased slightly, and total reserves of foreign-affiliated companies declined slightly, the share of reserves held by foreign affiliates declined from 18.1 percent to 17.4 percent (Table 36). With production up only slightly, the decline in the reserve share of foreign affiliates stems largely from a 46-percent decline in gross reserve additions. For natural gas, reserves held by foreign-affiliated companies were steady in 1997. Although their ratio of gross natural gas reserve additions to natural gas production declined to slightly less than one, their share of total U.S. reserves was essentially constant.

### Foreign Affiliates' U.S. Capital and Exploratory Spending Again Rises Strongly

Reserve acquisition, exploration, and development costs incurred by foreign affiliates in the United States rose 18 percent in 1997, in spite of the loss of foreign affiliation by two companies (Table 37). The most substantial increase was by Louis Dreyfus Natural Gas, which increased its upstream spending several times over. This was mostly the result of its acquisition of American Exploration, but the company also had large increases in exploration and development spending; it drilled almost 50 percent more wells in 1997 than it did in 1996. BP America, Forcenergy, and Anadarko Petroleum also had large increases in exploration and development spending. Forcenergy more than tripled its exploration spending while Anadarko more than doubled its development spending. In 1997, Shell Oil essentially sustained its large increase of 1996, mostly through expenditures in the Gulf of Mexico.

Oil and gas production in the United States by foreign-affiliated companies declined somewhat between 1992 and 1997. In contrast, upstream spending has increased every year since 1995, the year that EIA began compiling this statistic. However, this pattern suggests that a reversal of the production decline for foreign affiliates may be in the offing.

Capital expenditures by foreign-affiliated companies for petroleum refining, marketing, and pipelines declined for the second straight year in 1997 (Table 37). This is consistent with the declining role of foreign affiliates in petroleum refining in the United States. Both Shell Oil and PDV America had substantial declines in downstream capital expenditures. Star Enterprise was the only foreign-affiliated company to show an increase in downstream capital expenditures, in part because it began construction of a lubricant base oils complex at its Port Arthur, Texas refinery in 1997.

### Foreign Participation in Coal Mining Activity Declines

The foreign-affiliated companies' share of coal production declined in 1997, the first decline since 1991 (Figure 28 and Figure 29). This was almost totally due to the reclassification of two formerly foreign-affiliated U.S. coal companies (Table 38). Ashland Coal was merged with Arch Mineral to form Arch Coal in 1997. In the process, the share of Ashland's foreign parent (Carboex) in Arch Coal slipped below the 10-percent threshold for an FDI-related company. Costain Coal was wholly acquired by Rencoal (now Lodestar Holdings) from its parent company, Costain Group (United Kingdom). Rencoal was and Lodestar Holdings is controlled by a U.S. citizen who is its chairman and director.

Indicators of activity in the U.S. uranium industry were mixed in 1997. After rallying for the previous 3 years, uranium concentrate production in the United States fell 11 percent in 1997.[Note 116] However, total U.S. exploration and development expenditures by uranium raw materials producers more than tripled, to $30 million (Table 39). This increase is in part attributable to the increased price of uranium in 1995 and 1996. However, U.S. exploration and development expenditures contributed by foreign majority-owned companies decreased slightly in 1997. As a result, the share of exploration and development expenditures contributed by these companies fell to its lowest level since 1983.

A major development for foreign-affiliated uranium producers in 1997 was the acquisition of Power Resources and its Highland *in situ* leaching operation in Wyoming by Cameco (Canada). Highland is the largest uranium operation in the United States. Cameco said that one reason for the purchase was to provide access to operating expertise in the technology of *in situ* leaching.[Note 117] Since Magnox Electric (United Kingdom) formerly had largely owned Power Resources, its acquisition by Cameco did not result in any new foreign direct investment in the U.S. uranium industry.

## Financial Performance of Foreign-Affiliated Energy Companies

The financial performance of all U.S. petroleum and natural gas companies in 1997 exceeded that of 1996, which was itself a banner year for the companies. "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 [U.S. petroleum and natural gas] companies' bottom-line results."[Note 118] Improvements were particularly notable in U.S. refining and marketing, where net income for the major U.S. petroleum and natural gas companies increased by 40 percent. Net income from U.S. oil and gas production managed only a one-percent gain, largely because crude oil prices fell in 1997.

This pattern is evident in the financial performance of both foreign affiliates and other U.S. petroleum, natural gas, and coal companies. While revenues for both groups were down slightly, net income and cash flow increased for both groups (Table 40). However, foreign-affiliated companies increased their net income more than three times faster than other companies, while other companies showed stronger proportional gains in cash flow.

Total assets and, more noticeably, capital expenditures grew at substantially slower rates for foreign-affiliated petroleum, natural gas, and coal companies. Also, return on equity was lower for foreign-affiliated companies than for other energy companies in both 1996 and 1997.

## U.S. Companies' Direct Investment Abroad in Energy

The counterpart to FDI in the United States is U.S. direct investment abroad (DIA). The increase in direct investment in the U.S. petroleum and natural gas industry was second only to that in the finance (except depository institutions), insurance, and real estate industry in 1997. The 15-percent rate of growth of the U.S. DIA position in petroleum and natural gas in 1997 was higher than for any of the past 17 years (Table 41). The $11.2-billion increase in the petroleum and natural gas DIA position in 1997 capped eight years of growth in U.S. overseas investment in petroleum and natural gas. The increase in the DIA position in petroleum and natural gas was in contrast to the much smaller increase in the FDI position in U.S. petroleum and natural gas (Table 31). The gap between the two, which had been narrowing in the previous two years, broadened in 1997 (Figure 30). In general, that gap has been widening in the 1990's, reflecting the non-U.S. focus of worldwide petroleum and natural gas investment. Between 1990 and 1993, the FDI position in U.S. petroleum and natural gas declined by $11 billion.

### DIA Focused on Upstream Oil and Gas in Latin America, Europe, and Africa

The United Kingdom is far and away the main destination for U.S. direct investment abroad in petroleum and natural gas (Table 42). Norway is a distant second in Europe. Of course, the bulk of North Sea oil and gas production is in the waters of these two countries. The Asia and Pacific region is the second largest recipient of direct investment abroad in petroleum and natural gas, with Indonesia, Japan, and, to a lesser extent, Singapore as the lead recipients. However, the increase in the DIA position in the Asia and Pacific region in 1997 was moderate, in part likely because of the financial crisis that began that year in some Asia and Pacific countries. The two regions with the largest proportional gains in their DIA position in 1997 were Latin America and Other Western Hemisphere and Africa. Brazil, Argentina, and Venezuela all had substantial increases in Latin America, while Nigeria became the largest recipient of petroleum and natural gas DIA in Africa.

### Direct Investment Abroad in Electric Power

U.S. companies appear to be continuing their stepped-up direct investment abroad in electric power generation, transmission, and distribution (Figure 31). Although the Bureau of Economic Analysis does not publish the DIA position for electric power separately, it does report that the DIA position in electric, gas, and sanitary services increased $5.4 billion in 1997.[Note 119] Other publicly available data suggest that the DIA position in electric, gas, and sanitary services, at least in recent years, has been dominated by transactions in electric power. For example, publicly available information show that three of the large acquisitions abroad in electricity by U.S. companies in 1997 totaled $5.6 million. They were the purchase of the Yorkshire Electricity Group (the United Kingdom) for $2.6 billion by a joint venture of American Electric Power and the Public Service Co. of Colorado, the purchase of London Electricity (the United Kingdom) by Entergy for $2.1 billion, and the acquisition of PowerNet (Australia) by GPU for $1.9 billion. Since 1995, the DIA position in electric, gas, and sanitary services has been increasing more each year.[Note 120] Two factors are in part responsible for the increased DIA in electricity. One is the passage of the Energy Policy Act of 1992 in the United States, which removed Federal legislative impediments to investment in foreign ventures by U.S. utilities. The other is the ongoing privatization and deregulation of the electric power industry overseas.

A 1997 EIA analysis compared the characteristics of U.S. electric utilities with multinational operations to U.S. electric utilities that were wholly domestic.[Note 121] It found that, based on net fixed assets, U.S. multinational utilities grew faster than strictly domestic ones between 1987 and 1996. These findings are consistent with the position that privatization and deregulation overseas provide an investment channel for those U.S. utilities that placed a relatively high value on corporate growth.

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# Chapter 5 Endnotes

89. 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…."

90. In the United States, the criterion for foreign direct investment is specified by the International Investment and

Trade in Services Survey Act. The act defines foreign direct investment in the United States as "the ownership or control, directly or indirectly, by one foreign investor of 10 percent or more of the voting securities of an incorporated U.S. business enterprise, or the equivalent interest in an unincorporated U.S. business enterprise." See Alicia M. Quijano, "A Guide to BEA Statistics on Foreign Direct Investment in the United States," *Survey of Current Business*, (Washington, DC, February 1990), pp. 29-37, for further discussion. The percentage amount is, of necessity, "arbitrary," because it does not necessarily constitute control. Edward M. Graham and Paul R. Krugman, *Foreign Direct Investment in the United States*, 3rd ed. (Washington, DC: Institute for International Economics, 1995), p. 9.

91. For a comprehensive analysis of FDI in the United States, see Edward M. Graham and Paul R. Krugman, *Foreign Direct Investment in the United States*, 3rd ed. (Washington, DC: Institute for International Economics, 1995).

92. This section considers acquisitions and divestitures in the U.S. energy sector that could be identified as FDI and that could be valued. These data are all from publicly available sources.

93. NGC promptly sold many of Destec's assets for a total of $735 million. Both NGC's acquisition and its divestitures of Destec's assets are included in the totals for this report. Removing NGC's divestitures of Destec's assets still leaves the net Destec acquisition as the second largest FDI-related acquisition in 1997, at $525 million.

94. For discussions of the continuing transition in the U.S. electric power industry, see three reports by the Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996); *The Changing Structure of the Electric Power Industry: Selected Issues*, *1998*, DOE/EIA-0562(98) (Washington, DC, July 1998); and *The Changing Structure of the Electric Power Industry: Corporate Combinations*, release anticipated in December 1999.

95. One FDI-related electric power acquisition occurred previously. Transco sold its independent power producer, Transco Energy Ventures, to National Power America, a subsidiary of the United Kingdom's National Power, for $150 million in 1993. It also involved an independent power producer.

96. A recent discussion of some of these issues can be found in "Energy Companies Adjust to Changing Industry," *Oil & Gas Journal* (July 12, 1999), pp. 24-27.

97. In June 1999, Dynegy (formerly NGC) agreed to purchase Illinova, an energy services company and parent of Illinois Power, in a deal valued at nearly $2 billion. Concurrently, NOVA and BG plan to relinquish their interests in Dynegy for cash.

98. For example, Christopher F. Corr, "A Survey of United States Controls on Foreign Investment and Operations: How Much is Enough," *The American University Journal of International Law and Policy*, (Winter 1994) and Unit for Relations with the United States of America, European Commission, "Report on United States Barriers to Trade and Investment (July 1997).

99. As early as 1973, the Atomic Energy Commission approved the transfer of nuclear assets to a company 50-percent owned by foreign entities. See Nuclear Regulatory Commission, "Preliminary Staff Views Concerning its Review of the Foreign Ownership Aspects of Amergen, Inc.'s Proposed Purchase of Three Mile Island, Unit 1," SECY-98-252 (October 30, 1998).

100. Nuclear Regulatory Commission, "NRC Approves Transfer of Three Mile Island Plant Operating License to Amergen Energy Co.," press release (April 13, 1999).

101. Nuclear Regulatory Commission, "[Draft] Standard Review Plan on Foreign Ownership, Control, or Domination," *Federal Register* (March 2, 1999), pp. 10166-10169. The final guidelines were approved on August 30, 1999. Also the NRC has asked Congress to delete the foreign ownership restrictions in the Atomic Energy Act.

102. An applicant that is wholly owned by a foreign corporation is, in most cases, ineligible for a license.

103. Statoil, press release (May 21, 1997).

104. Ashland underwent major restructuring in 1997. In addition to spinning-off Blazer, Ashland combined its petroleum refining, marketing, and transportation assets with Marathon Oil, creating Marathon Ashland Petroleum, and merged its two major coal investments into one unit.

105. Louis Dreyfus Natural Gas, press release (June 24, 1997).

106. Ultramar Diamond Shamrock, press release (September 25, 1997).

107. More specifically, it is the year-end book value of the foreign parent group's equity (including retained earnings)

in, and net outstanding loans to, their U.S. affiliates. In other words, it is the cumulative value of net capital inflows from foreign direct investors.

108. The industry of the transaction is sometimes determined by the industry of the ultimate beneficial owner of the U.S. affiliate. Data categorized this way are published less extensively than are data by the industry of the U.S. affiliate.

109. Sylvia E. Bargas, "Direct Investment Positions for 1997, Country and Industry Detail" *Survey of Current Business*, (Washington, DC, July 1998), p. 35.

110. The 15-percent increase between 1996 and 1997 was the largest rate of increase since 1989.

111. Mahnaz Fahim-Nader and William J. Zeile, "Foreign Direct Investment in the United States: New Investment in 1997 [and] Affiliate Operations in 1996," *Survey of Current Business*, (Washington, DC, June 1998), Table 17.

112. Total, *Annual Report*, 1997, http://www.total.com/us/ar97/97chair.htm (August 30, 1999).

113. TrizecHahn, *Annual Report*, 1997, p. 56..

114. The number of one foreign-affiliated company's retail outlets could not be verified for 1997.

115. Production by one foreign-affiliated company could not be verified for 1997.

116. Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 5.

117. Cameco, press release (January 13, 1997).

118. Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), p. 7.

119. Bureau of Economic Analysis, "U.S. Direct Investment Abroad: Detail for Historic-Cost Position and Related Capital and Income Flows, 1997," *Survey of Current Business* (Washington, DC, October 1998), Table 17.

120. However, annual capital outflows have not increased in the last 2 years. Since changes in the DIA position are the sum of capital outflows and valuation adjustments, the latter have been the source of the increase in 1996 and 1997. Valuation adjustments account for differences between changes in the position, measured at book value, and capital flows, measured at transactions value. They include currency-translation adjustments, adjustments for differences between exchange amounts and book values, writeoffs for uncompensated expropriations of assets, and capital gains and losses.

121. Energy Information Administration, *Electricity Reform Abroad and U.S. Investment*, DOE/EIA-0616 (Washington, DC, October 1997), Chapter 1.

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**Table 29.**
**Value of Foreign Acquisitions and Divestitures in U.S. Energy, 1991-1997**
(Million Dollars)

| | **1991** | **1992** | **1993** | **1994** | **1995** | **1996** | **1997** |
|---|---|---|---|---|---|---|---|
| **Acquisitions** | | | | | | | |
| Oil and Gas Production[a] | 1,043 | 949 | 1,246 | 159 | 2,570 | 368 | 1,386 |
| Midstream Natural Gas | NA | NA | NA | 170 | 367 | 1,252 | 150 |
| Petroleum Refining and Marketing | 103 | 173 | 1,264 | 0 | 339 | 50 | 313 |
| Coal | 570 | 1,276 | 1,928 | 674 | 0 | 204 | 99 |
| Electric Power[b] | NA | NA | 150 | 0 | 0 | 0 | 1,390 |
| **Total Acquisitions** | 1,716 | 2,398 | 4,588 | 1,003 | 3,276 | 1,874 | 3,338 |
| **Divestitures** | | | | | | | |
| Oil and Gas Production[a] | 736 | 461 | 938 | 663 | 699 | 660 | 340 |
| Midstream Natural Gas | NA | NA | NA | 0 | 167 | 123 | 0 |
| Petroleum Refining and Marketing | 400 | 60 | 822 | 41 | 0 | 679 | 959 |
| Coal[c] | 155 | 869 | 438 | 768 | 110 | 0 | 47 |
| Electric Power[d] | NA | NA | NA | NA | NA | NA | 528 |
| **Total Divestitures** | 1,291 | 1,390 | 2,198 | 1,472 | 976 | 1,462 | 1,874 |

[a] Includes drilling and drilling services.

[b] 1997 includes NGC's acquisition of all of Destec.

[c] 1992 includes Shell Oil's divestiture of its coal operations for $850 million.

[d] 1997 includes NGC's divestiture of Destec's international assets to AES.

NA=Not available.

Note: 1997 acquisitions and divestitures do not include Peabody's acquisition by Energy Group (United Kingdom) nor divestiture by Hanson (United Kingdom) because it was a transaction between foreign investors and does not change the amount of FDI. 1995 divestitures do not include Du Pont's $8.8-billion stock buyback.

Sources: **1997:** Tables A1, A2, and A3 in Appendix A. **1991-1996:** Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), Table 26.

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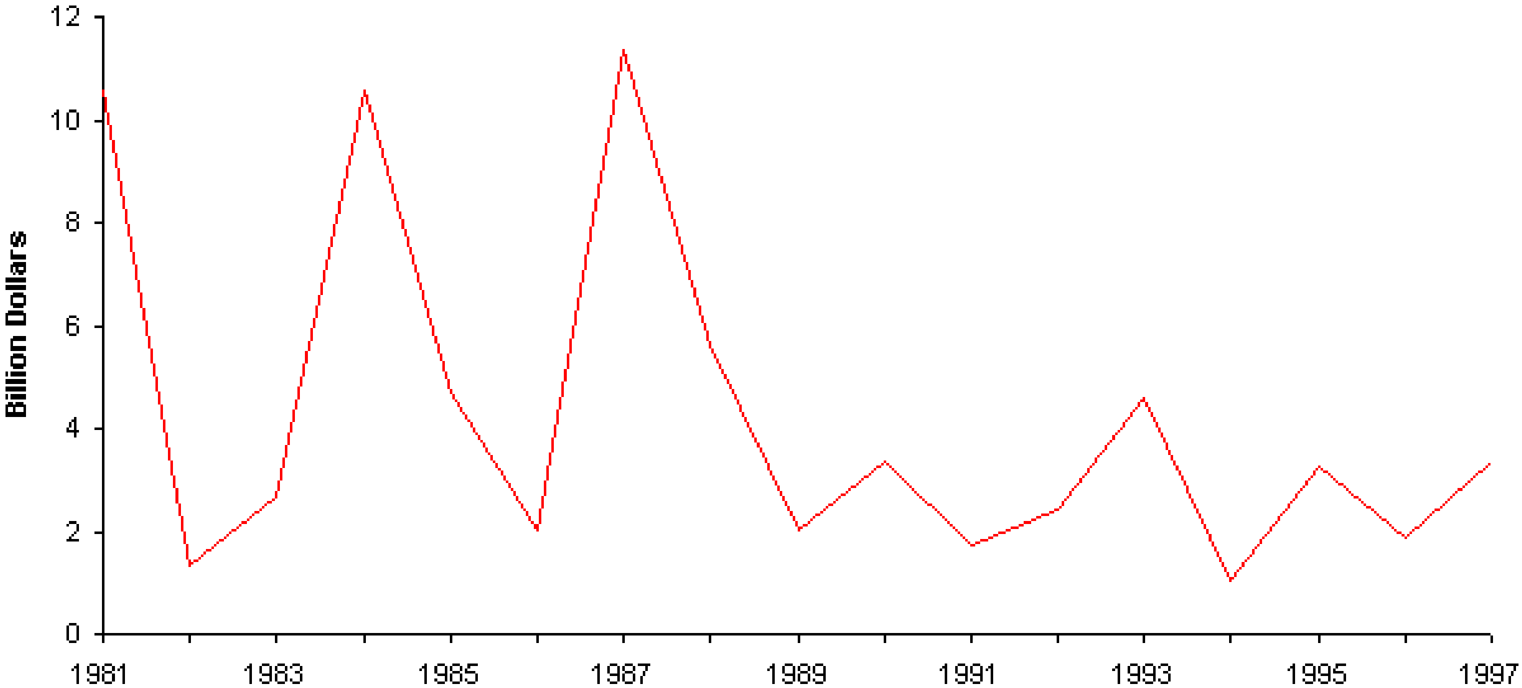
**Figure 26. Value of Foreign Direct Investment-Related Acquisitions in U.S. Energy, 1981-1997**




Sources: **1997**: Tables A1, A2, and A3 in Appendix A. **1981-1996**: Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), Figure 35.

**Table 30.**
**Geographic Sources of the Foreign Direct Investment Position in U.S. Industry, 1995-1997**
(Billion Dollars)

| Region | Foreign Direct Investment Position | | | Net Change | |
|---|---|---|---|---|---|
| | 1995 | 1996 | 1997 | 1996 | 1997 |
| All Countries | 535.6 | 594.1 | 681.7 | 58.5 | 87.6 |
| | | | | | |
| Canada | 45.6 | 54.8 | 64.0 | 9.2 | 9.2 |
| | | | | | |
| Europe | 332.4 | 368.3 | 425.2 | 35.9 | 56.9 |
| United Kingdom | 116.3 | 121.3 | 129.6 | 5.0 | 8.3 |
| Netherlands | 65.1 | 74.3 | 84.9 | 9.2 | 10.5 |
| Germany | 46.0 | 59.9 | 69.7 | 13.8 | 9.8 |
| France | 36.2 | 41.1 | 47.1 | 5.0 | 6.0 |
| Switzerland | 27.5 | 30.4 | 38.6 | 2.9 | 8.2 |
| | | | | | |
| Latin America and OWH[a] | 27.9 | 29.2 | 35.7 | 1.3 | 6.5 |
| UK Islands, Caribbean | 7.2 | 7.6 | 12.0 | 0.4 | 4.4 |
| Netherlands Antilles | 8.0 | 9.3 | 7.7 | 1.3 | -1.6 |
| Panama | 4.9 | 5.8 | 6.6 | 0.9 | 0.8 |
| | | | | | |
| Japan | 105.0 | 114.5 | 123.5 | 9.5 | 9.0 |
| | | | | | |
| Australia | 10.4 | 13.9 | 16.2 | 3.5 | 2.4 |
| | | | | | |
| Other OPEC[b] | 4.0 | 4.2 | 4.7 | 0.2 | 0.5 |

[a]Other Western Hemisphere.

[b]Excludes Venezuela. OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Indonesia, Iraq, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1998), Tables 10.2-10.4.

*Last Updated on 12/9/99*

**Table 31**
**Foreign Direct Investment Position in U.S. Petroleum and Natural Gas and Coal, 1980-1997**
(Billion Dollars)

| | Foreign Direct Investment Position in the United States | | | Percent of Total | |
|---|---|---|---|---|---|
| | Petroleum and Natural Gas[a] | Coal | All Industries | Petroleum and Natural Gas | Coal |
| 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[a] | 32.3 | 0.6 | 480.7 | 6.7 | 0.1 |
| 1995 | 33.9 | 0.6 | 535.6 | 6.3 | 0.1 |
| 1996 | 43.8 | 0.8 | 594.1 | 7.4 | 0.1 |
| 1997 | 47.7 | 0.9 | 681.7 | 7.0 | 0.1 |

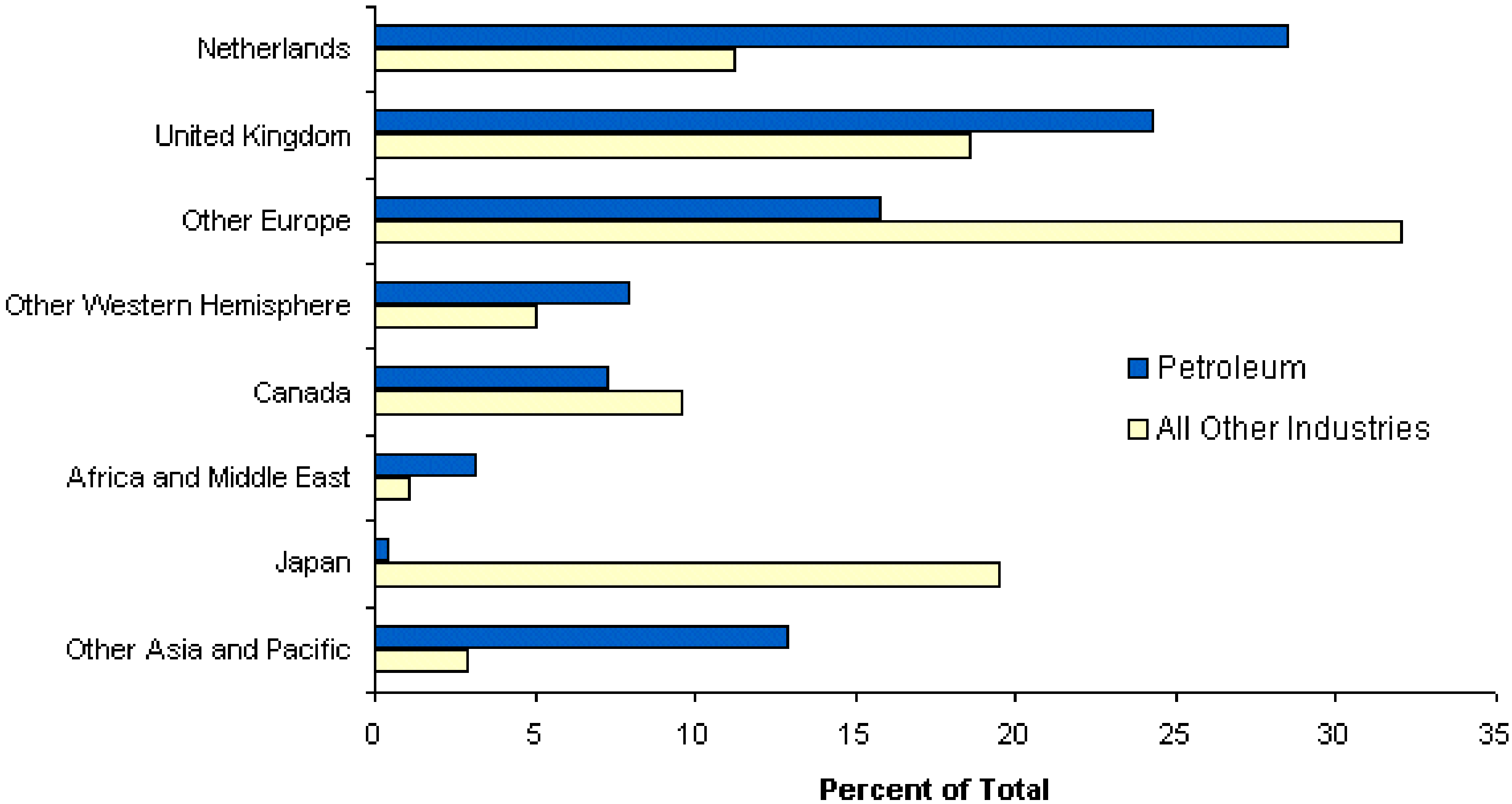
[a]In 1998, the Bureau of Economic Analysis reclassified intercompany debt and associated interest transactions between parent companies and their affiliates that are nondepository financial intermediaries from direct investment to transactions with unaffiliated foreigners for the years 1994-1997. Thus, there is a break between 1993 and 1994 in the All Industries and Percent of Total series.

Notes: 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. Amounts are on a historical-cost, or book-value, basis. 1997 estimates are preliminary; 1994-1996 estimates are revised. (The Bureau of Economic Analysis usually continues to revise FDI data for three years after they are first published.) Sum of components may not equal total due to independent rounding.

Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1998), Table 17.

*Last Updated on 12/9/99*

**Figure 27. Shares of the Foreign Direct Investment Position by Country (of Investor) in the Petroleum, and All Other U.S. Industries, 1997**




Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1998), Table 10.4.

**Table 32.**
**Geographic Sources of the Foreign Direct Investment Position in U.S. Petroleum and Natural Gas, 1995-1997**
(Million Dollars)

| | Foreign Direct Investment Position in U.S. Petroleum and Natural Gas | | | Net Additions | |
|---|---|---|---|---|---|
| | 1995 | 1996 | 1997 | 1996 | 1997 |
| All Countries | 34,907 | 43,770 | 47,679 | 8,863 | 3,909 |
| | | | | | |
| Canada | 3,241 | 3,515 | 3,446 | 274 | -69 |
| | | | | | |
| Europe | 24,039 | 29,285 | 32,627 | 5,246 | 3,342 |
| United Kingdom | 9,275 | 10,856 | 11,568 | 1,581 | 712 |
| Netherlands | 11,588 | 12,516 | 13,561 | 928 | 1,045 |
| Belgium | (c) | (c) | 1,265 | (c) | (c) |
| | | | | | |
| Asia and Pacific | 4,415 | 6,454 | 6,350 | 2,039 | -104 |
| Australia | (c) | (c) | 6,528 | (c) | (c) |
| Japan | 83 | 118 | 214 | 35 | 96 |
| | | | | | |
| Latin America and OWH[a] | 2,032 | 3,160 | 3,766 | 1,128 | 606 |
| Netherlands Antilles | (c) | 2,701 | 2,561 | (c) | -140 |
| | | | | | |
| Other OPEC[b] | 1,135 | 1,315 | (c) | 180 | (c) |

[a]Other Western Hemisphere.

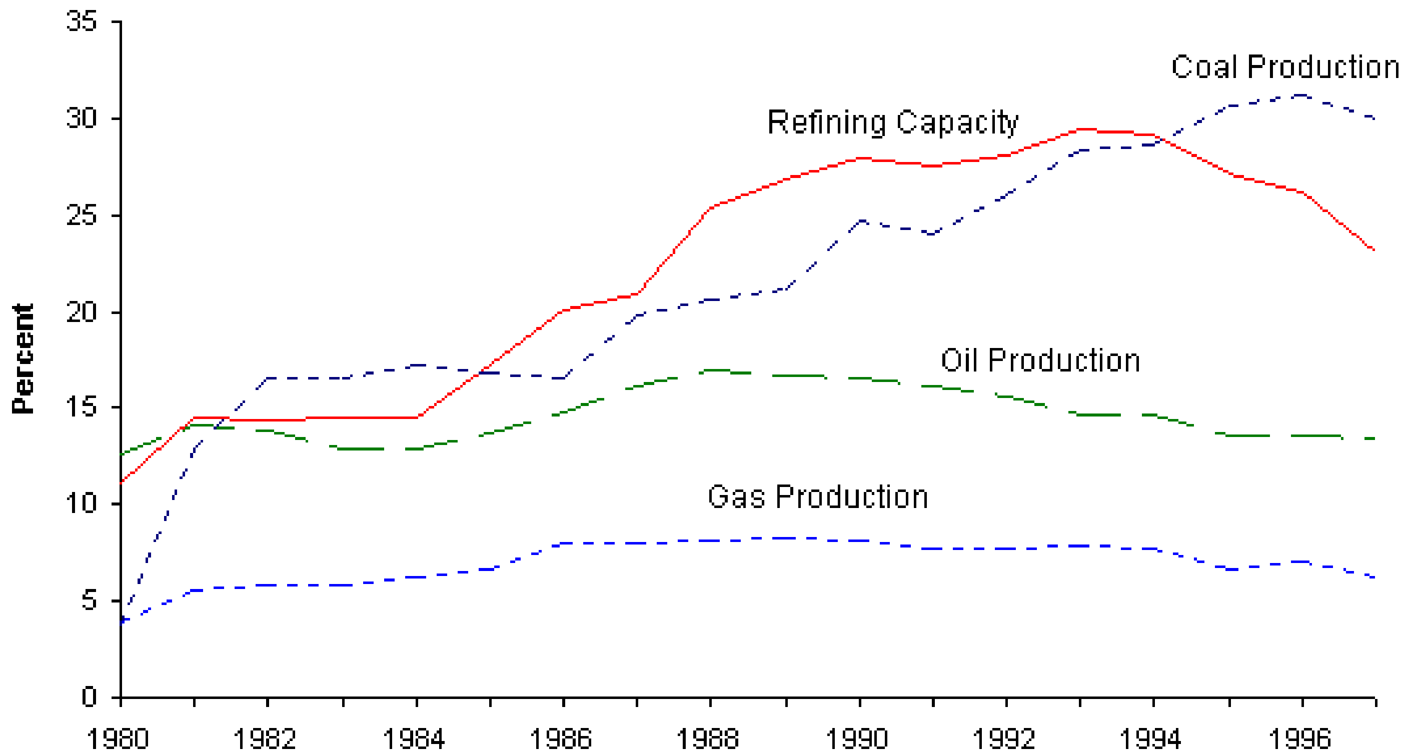
[b]Excludes Venezuela. OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Indonesia, Iraq, Iran, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[c]Data withheld by the Bureau of Economic Analysis to prevent disclosure of individual company information.

Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1998), Tables 10.2-10.4.

*Last Updated on 12/9/99*

**Figure 28. Foreign Affiliates' Share of U.S. Production of Oil, Gas, and Coal, and of U.S. Refining Capacity, 1980-1997**




Sources: **1997**: Tables 6, 7, and 11. **1980-1996**: Energy Information Administration, *Performance Profiles of Major Energy Producers 1998*, DOE/EIA-0206(97) (Washington, DC, January 1998), Figure 37.

## Table 33.
## U.S. Refinery Operations of Foreign-Affiliated Companies, 1995-1997

| Company | Number of Refineries | | | Total Crude Oil Distillation Capacity (thousand barrels per day) | | |
|---|---|---|---|---|---|---|
| | 1995 | 1996 | 1997 | 1995 | 1996 | 1997 |
| Shell Oil | 6 | 7 | 7 | 796 | 897 | 920 |
| Petroleos de Venezuela | 4 | 4 | 5 | 545 | 542 | 687 |
| Star Enterprise | 3 | 3 | 3 | 605 | 605 | 600 |
| BP America | 4 | 3 | 3 | 694 | 551 | 551 |
| Deer Park[a] | 1 | 1 | 1 | 265 | 256 | 269 |
| Lyondell-Citgo | 1 | 1 | 1 | 265 | 258 | 239 |
| Fina | 2 | 2 | 2 | 234 | 237 | 230 |
| BHP Petroleum Americas | 1 | 1 | 1 | 95 | 95 | 95 |
| Neste Trifinery Petroleum | 0 | 0 | 1 | 0 | 0 | 30 |
| Transworld Oil USA (Calcasieu) | 1 | 1 | 1 | 13 | 14 | 15 |
| Uno-Ven | 1 | 1 | (b) | 145 | 145 | (b) |
| Clark USA | 3 | 3 | NF | 309 | 309 | NF |
| Total Petroleum North America | 4 | 3 | NF | 198 | 142 | NF |
| | | | | | | |
| **Total Foreign-Affiliated** | 31 | 30 | 25 | 4,164 | 4,050 | 3,637 |
| | | | | | | |
| **Total United States** | 169 | 163 | 159 | 15,354 | 15,433 | 15,840 |
| | | | | | | |
| **Percent Foreign-Affiliated** | 18.3 | 18.4 | 15.7 | 27.1 | 26.2 | 23.0 |

[a]Formerly Shell Oil/PMI Holdings.

[b]Uno-Ven wholly acquired by Petroleos de Venezuela in 1997.

NF = Not foreign-affiliated at year end.

Sources: *Oil and Gas Journal* (December 22, 1997) and previous issues.

*Last Updated on 12/15/99*

## Table 34
## Branded Retail Outlets and Total Gasoline Sales in the United States by Foreign-Affiliated Companies, 1996-1997

| | 1996 | 1997 |
|---|---|---|
| **Number of Outlets** | | |
| Citgo Petroleum | 14,529 | 14,885 |
| Shell Oil | 8,900 | 9,300 |
| Star Enterprise[a] | 9,378 | 9,378 |
| BP America | 6,752 | 6,775 |
| Fina | 2,571 | 2,571 |
| PDV America[b] | 2,247 | 2,300 |
| Hawaiian Independent Refinery | 30 | 32 |
| Total Petroleum North America | 2,106 | NF |
| Clark USA | 863 | NF |
| | | |
| **Total for Foreign-Affiliated Companies[c]** | 47,376 | 45,241 |
| **U.S. Total[d]** | 187,892 | 182,596 |
| **Foreign-Affiliated Companies as Percent of U.S. Total** | 25.2 | 24.8 |
| | | |
| **Total Gasoline Sales[e] (thousand barrels per day)** | | |
| **Foreign-Affiliated Companies[f]** | 2,145 | 1,998 |
| **All Companies** | 8,082 | 8,195 |
| **Foreign-Affiliated Companies as a Percent of U.S. Total** | 26.5 | 24.4 |

[a]Not publicly reported for 1997; assumed unchanged from 1996.

[b]Uno-Ven in 1996, was wholly acquired by Petroleos de Venezuela in 1997.

[c]Includes company-owned outlets and independent dealer outlets.

[d]The total includes all establishments selling gasoline at retail.

[e]Gasoline sales by "Prime Suppliers."

[f]Disaggregated company numbers are considered proprietary by the Energy Information Administration.

NF = No foreign-affiliated at yearend.

Sources: **Company station counts and total branded outlets**: *National Petroleum News,* Market Facts 1997 (Mid-July 1998), and previous issue, and company press releases. **Foreign affiliates' sales**: Energy Information Administration, Form EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption." **All companies' sales**: Energy Information Administration, *Petroleum Marketing Annual 1997*, DOE/EIA-0487(97) (Washington, DC, December 1998), Table 48, and previous issue.

**Table 35.**
**Net Production of Crude Oil and Natural Gas Liquids and Dry Natural Gas in the United States by Foreign-Affiliated Companies, 1995-1997**

| | **Crude Oil and Natural Gas Liquids** (thousand barrels per day) | | | **Dry Natural Gas** (billion cubic feet) | | |
|---|---|---|---|---|---|---|
| | **1995** | **1996** | **1997** | **1995** | **1996** | **1997** |
| BP America[a] | 572.6 | 562.8 | 553.4 | 23.0 | 29.0 | 34.0 |
| Shell Oil | 441.1 | 450.8 | 490.4 | 644.0 | 658.0 | 630.0 |
| Anadarko Petroleum | 30.1 | 27.9 | 39.7 | 172.0 | 165.0 | 179.0 |
| Forcenergy Gas Exploration | 6.4 | 11.0 | 22.5 | 21.1 | 32.7 | 57.7 |
| Canadian Occidental | 9.6 | 11.2 | 11.0 | 16.0 | 24.0 | 29.0 |
| Fina | 10.3 | 10.4 | 10.4 | 52.1 | 56.7 | 69.7 |
| Norcen Energy Resources[b] | 4.9 | 5.9 | NA | 40.5 | 48.7 | 48.7 |
| Louis Dreyfus Natural Gas | 4.6 | 5.1 | 5.7 | 51.3 | 63.9 | 71.3 |
| Total Minatome | 6.7 | 6.0 | 4.6 | 32.0 | 34.0 | 34.9 |
| BHP Petroleum (Americas) | 8.5 | 4.9 | 4.3 | 38.5 | 27.7 | 12.5 |
| Saba Petroleum | 1.9 | 2.2 | 3.1 | 0.9 | 1.1 | 1.7 |
| Chieftain Development International | 1.6 | 2.0 | 2.6 | 10.1 | 23.0 | 24.3 |
| Elf Aquitaine | 1.4 | 1.5 | 1.5 | 21.6 | 25.0 | 22.5 |
| YPF | 1.1 | 1.2 | 1.4 | 47.5 | 53.1 | 52.6 |
| Cairn Energy USA | 1.2 | 0.7 | NF | 10.4 | 10.2 | NF |
| Other Companies | 1.4 | 1.2 | (s) | 10.1 | 13.1 | 0.4 |
| **Total Foreign-Affiliated** | 1,103 | 1,105 | 1,151 | 1,191 | 1,265 | 1,268 |
| | | | | | | |
| **Total United States** | 8,626 | 8,607 | 8,611 | 18,599 | 18,793 | 18,902 |
| | | | | | | |
| **Percent Foreign-Affillated** | 12.8 | 12.8 | 13.4 | 6.4 | 6.7 | 6.7 |

[a]Excludes natural gas consumed in Alaskan operations.

[b]Not found for 1997, assumed unchanged from 1996.

[s] = Less than 0.05.

NA = Not publicly reported; NF = Not foreign-affiliated at year end.

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 filed with the U.S. Securities and Exchange Commission and annual reports to shareholders. **U.S. Totals**: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/03) (Washington, DC, March 1999), Tables 3.1a and 4.1.

*Last Updated on 12/9/99*

**Table 36.**
**U.S. Oil and Natural Gas Proved Reserves and Production for Foreign-Affiliated Companies, 1996 and 1997**

| 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, 1996 | 5,411 | 29,840 | 18.1 |
| December 31, 1997 | 5,318 | 30,519 | 17.4 |
| 1996 Production | 403 | 3,023 | 13.3 |
| 1997 Production | 420 | 3,002 | 14.0 |
| 1996 Gross Reserve Additions[b] | 612 | 3,113 | 19.7 |
| 1997 Gross Reserve Additions[b] | 329 | 3,681 | 8.9 |
| 1996 Ratio of Gross Reserve Additions to Production | 1.51 | 1.03 | NM |
| 1997 Ratio of Gross Reserve Additions to Production | 0.78 | 1.23 | NM |
| | | | |
| **Dry Natural Gas Proved Reserves** | (billion cubic feet) | | |
| December 31, 1996 | 13,642 | 166,474 | 8.2 |
| December 31, 1997 | 13,581 | 167,223 | 8.1 |
| 1996 Production | 1,265 | 18,861 | 6.7 |
| 1997 Production | 1,268 | 19,211 | 6.7 |
| 1996 Gross Reserve Additions[b] | 1,459 | 20,189 | 7.2 |
| 1997 Gross Reserve Additions[b] | 1,132 | 19,960 | 5.7 |
| 1996 Ratio of Gross Reserve Additions to Production | 1.16 | 1.07 | NM |
| 1997 Ratio of Gross Reserve Additions to Production | 0.95 | 1.04 | 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 1997.

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

NM = Not meaningful.

| |
|---|
| Sources: **Foreign-affiliated data:** Companies' Form 10-K reports 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 1997 Annual Report*, DOE/EIA-0216(97) (Washington, DC, December 1998). |

*Last Updated on 12/15/99*

## Table 37.
## U.S. Capital and Exploratory Expenditures of Foreign-Affiliated Petroleum and Natural Gas Companies, 1995-1997

| Company | Upstream[a] | | | | | Company | Downstream[b] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1995 | 1996 | 1997 | 1995-1996 | 1996-1997 | | 1995 | 1996 | 1997 | 1995-1996 | 1996-1997 |
| | (million dollars) | | | (percent change) | | | (million dollars) | | | (percent change) | |
| Shell Oil | 1,642 | 2,380 | 2,229 | 45 | -6 | Shell Oil | 1,065 | 726 | 554 | -32 | -24 |
| BP America | 875 | 972 | 1,191 | 11 | 23 | PDV America[c] | 540 | 580 | 329 | 7 | -43 |
| Louis Dreyfus Natural Gas | 185 | 134 | 603 | -28 | 350 | Star Enterprise | 296 | 192 | 338 | -35 | 76 |
| Forcenergy | 144 | 283 | 493 | 97 | 74 | BP America | 210 | 195 | 195 | -7 | 0 |
| Anadarko Petroleum | 225 | 265 | 442 | 18 | 67 | Fina | 42 | 72 | 48 | 71 | -33 |
| Fina | 83 | 155 | 170 | 87 | 10 | Total Petroleum | 74 | 53 | NF | -28 | NM |
| Canadian Occidental | 130 | 161 | 166 | 24 | 3 | Clark USA | 42 | 45 | NF | 7 | NM |
| Norcen Energy Resources | 48 | 97 | 137 | 102 | 41 | | | | | | |
| YPF | 647 | 68 | 73 | -89 | 7 | | | | | | |
| Chieftain International | 87 | 56 | 68 | -36 | 21 | | | | | | |
| BHP Petroleum (Americas) | 140 | 121 | NA | -14 | NM | | | | | | |
| Cairn Energy USA | 46 | 49 | NF | 7 | NM | | | | | | |
| Presidio Oil | 18 | NF | NF | NM | NM | | | | | | |
| **Total** | **4,270** | **4,741** | **5,571** | **11** | **18** | **Total** | **2,269** | **1,863** | **1,464** | **-18** | **-21** |

[a]Includes costs incurred in oil and gas acquisition, exploration, development, and production.

[b]Includes capital expenditures in 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. The position in Uno-Ven was liquidated on May 1, 1997.

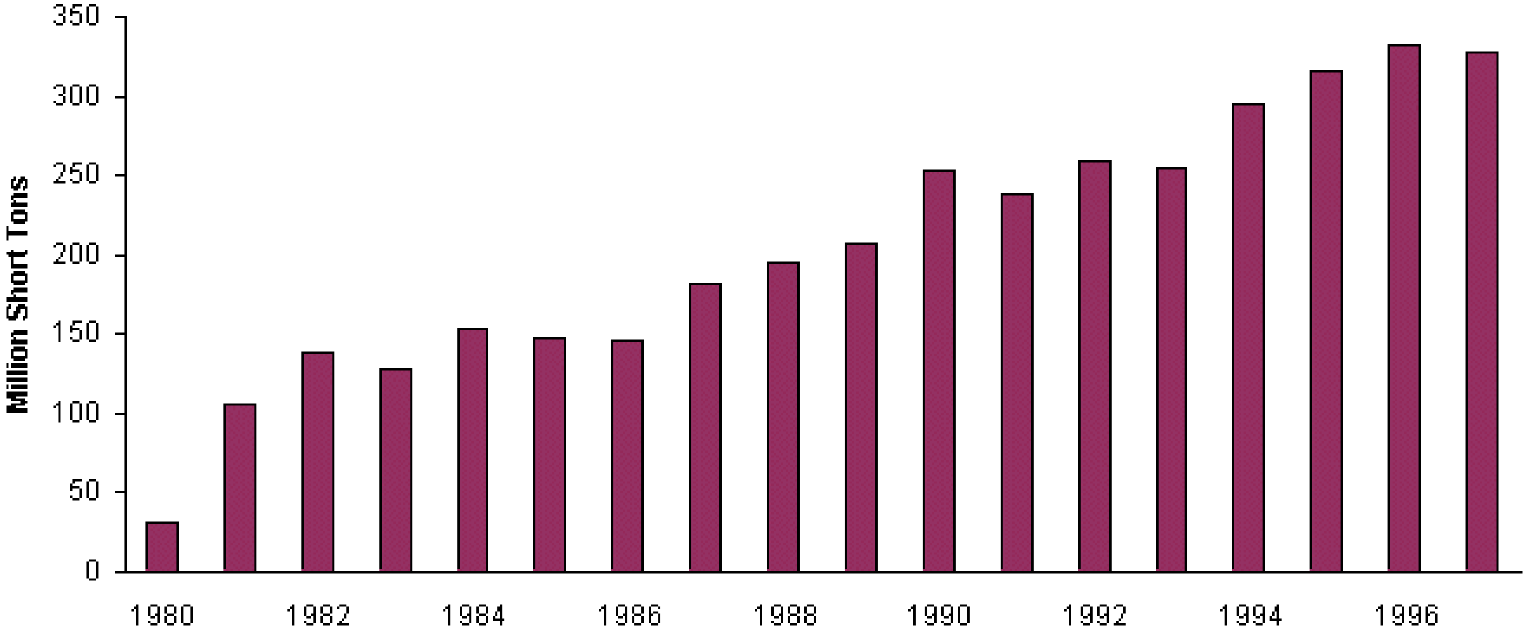
NA = not publicly reported; NF= not foreign-affiliated at year end; NM = not meaningful.

Notes: Norcen excludes acquisitions. PDV is taken from their Consolidated Cash Flow Statement. Star is estimated from Texaco's Capital and Exploratory Expenses of Equity Affiliates.

Sources: Company annual reports.

*Last Updated on 12/14/99*

**Figure 29. Production of U.S. Bituminous Coal and Lignite for Foreign-Affiliated U.S. Companies, 1980-1997**




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. **1990-1997**: Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), Table 15, and previous issues.

**Table 38.**
**U.S. Coal Production and Source of Ownership of Foreign-Affiliated Companies, 1996-1997**
(Thousand Short Tons)

| Foreign-Affiliated Company (Parent Company) | 1996 | 1997 |
|---|---|---|
| Peabody Holding (Energy Group) | 142,811 | 142,473 |
| Consol Coal (Rheinbraun) | 70,072 | 72,822 |
| Kennecott Energy (RTZ) | 62,527 | 78,950 |
| BHP Utah Minerals (Broken Hill Proprietary) | 13,228 | 14,318 |
| Canyon Fuel (Itochu Coal International) | 9,678 | 10,479 |
| Andalex Resources (Andalex Resources) | 7,613 | 7,645 |
| Carter-Roag Coal (Marquard and Bahls Coal) | 542 | 461 |
| Ashland Coal (Carborex) | 16,091 | NF |
| Costain Coal (Costain) | 9,342 | NF |
| **Total Foreign-Affiliated** | **331,904** | **327,148** |
| | | |
| **Total United States** | **1,063,856** | **1,089,932** |
| | | |
| **Percent Foreign-Affiliated** | **31.2** | **30.0** |

NF = Not foreign-affiliated at year end.

Note: Coal production refers to bituminous coal, subbituminous coal, and lignite coal production only.

Sources: Energy Information Administration, *Coal Industry Annual 1997*, DOE/EIA-0584(97) (Washington, DC, December 1998), and previous issue.

*Last Updated on 12/2/99*

**Table 39.**
**Foreign Contributions to U.S. Companies' Uranium Exploration and Development, 1977-1997**
(Million Dollars)

| | Foreign Contributions to U.S. Exploration and Development Expenditures | Total U.S. Exploration and Development Expenditures | Foreign Contributions as a Percent of U.S. Total | Number of U.S. Companies Reporting Foreign Contributions |
|---|---|---|---|---|
| 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 |
| 1997 | 4.3 | 30.4 | 14 | 4 |

Note: Foreign contributions are defined as contributions by enterprises that are majority-owned by non-U.S. entities.

Sources: Energy Information Administration, *Uranium Industry Annual 1997,* DOE/EIA-0478(97) (Washington, DC, April 1998), Table 2, and preceding issues. **Number of Companies, 1995 - 1997**: Energy Information Administration, Form EIA-858, "Uranium Industry Annual Survey" (1995 - 1997).

*Last Updated on 12/9/99*

## Table 40.
## Selected Financial Information for Foreign-Affiliated U.S. Petroleum and Natural Gas and Coal Companies, 1996-1997
(Billion Dollars)

| | Foreign-Affiliated U.S. Petroleum and Natural Gas and Coal Companies[a] | | | U.S. Petroleum and Natural Gas and Coal Comparison Group[b] | | |
|---|---|---|---|---|---|---|
| | 1996 | 1997 | Percent Change | 1996 | 1997 | Percent Change |
| **Financial Items** | | | | | | |
| Revenues | 67.6 | 65.2 | -3.6 | 480.3 | 479.7 | -0.1 |
| Net Income | 3.7 | 4.1 | 10.8 | 28.6 | 29.5 | 3.1 |
| Cash Flow[c] | 8.4 | 8.8 | 4.8 | 57.9 | 62.9 | 8.6 |
| Capital Expenditures | 8.1 | 8.4 | 3.7 | 47.7 | 60.7 | 27.3 |
| Cash Dividends | 2.2 | 2.3 | 4.5 | 12.4 | 13.3 | 7.3 |
| Total Assets | 65.4 | 66.3 | 1.4 | 446.1 | 470.5 | 5.5 |
| | | | | | | |
| | (percent) | | | | | |
| **Financial Ratios** | | | | | | |
| Return on Equity[d] | 12.3 | 13.1 | | 15.8 | 14.9 | |
| Dividends/Net Income | 58.6 | 55.5 | | 43.6 | 45.2 | |
| Dividends/Cash Flow | 25.9 | 25.6 | | 21.5 | 21.2 | |
| Debt/Equity[e] | 26.6 | 28.8 | | 44.8 | 47.0 | |

[a]Includes incorporated U.S. petroleum and natural gas and coal companies that were foreign-affiliated at 1997 yearend 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 **1996** these companies were: Anadarko Petroleum, Arabian Shield Development, Arakis Energy, Blue Dolphin Energy, Cairn Energy USA, Canadian Occidental Petroleum, Caspen Oil, Chieftain International, Citgo Petroleum, Clark Refining and Marketing, Fina, Forcenergy, Hondo Oil and Gas, Louis Dreyfus Natural Gas, Lyondell Petrochemical, MSR Exploration, Dynegy, Norcen Energy Resources, Oceanic Exploration, Penn Virginia, Ranger Oil, Rio Algom, Saba Petroleum, Santa Fe Energy Resources, Santa Fe International, Schlumberger, Shell Oil, Total Petroleum (North America) and Westmoreland Coal. The following companies were no longer foreign affiliated in 1997: Clark Refining & Marketing, Penn Virginia Corp., Santa Fe Energy Resources, Total Petroleum (North America), and Westmoreland Coal.

[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 subtracting 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 yearend stockholders' equity.

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

Note: Percent changes were calculated from unrounded data.
Source: Compiled from PC Compustat Industrial File and company annual reports.

*Last Updated on 12/9/99*

## Table 41.
## U.S. Direct Investment Abroad Position in Petroleum and Natural Gas, 1980-1997

| | U.S. Direct Investment Position Abroad in Petroleum and Natural Gas[a] | | Total U.S. Direct Investment Position Abroad[a] | | Petroleum and Natural Gas as Share of Total |
|---|---|---|---|---|---|
| | Billion Dollars | Percent Change | Billion Dollars | Percent Change | Percent |
| 1980 | 47.6 | -- | 215.4 | -- | 22.1 |
| 1981 | 53.2 | 11.8 | 228.3 | 6.0 | 23.3 |
| 1982 | 57.8 | 8.6 | 207.8 | -9.0 | 27.8 |
| 1983 | 57.6 | -0.3 | 207.2 | -0.3 | 27.8 |
| 1984 | 58.1 | 0.9 | 211.5 | 2.1 | 27.5 |
| 1985 | 57.7 | -0.7 | 230.2 | 8.8 | 25.1 |
| 1986 | 58.5 | 1.4 | 259.8 | 12.9 | 22.5 |
| 1987 | 59.8 | 2.2 | 314.3 | 21.0 | 19.0 |
| 1988 | 57.8 | -3.3 | 335.9 | 6.9 | 17.2 |
| 1989 | 48.3 | -16.4 | 381.8 | 13.7 | 12.7 |
| 1990 | 52.8 | 9.3 | 430.5 | 12.8 | 12.3 |
| 1991 | 57.7 | 9.3 | 467.8 | 8.7 | 12.3 |
| 1992 | 58.5 | 1.4 | 502.0 | 7.3 | 11.7 |
| 1993 | 64.2 | 9.7 | 564.3 | 12.4 | 11.4 |
| 1994[b] | 67.6 | 5.3 | 612.9 | NM | 11.0 |
| 1995 | 68.6 | 1.5 | 699.0 | 14.1 | 9.8 |
| 1996 | 74.5 | 8.5 | 777.2 | 11.2 | 9.6 |
| 1997 | 85.7 | 15.1 | 860.7 | 10.7 | 10.0 |

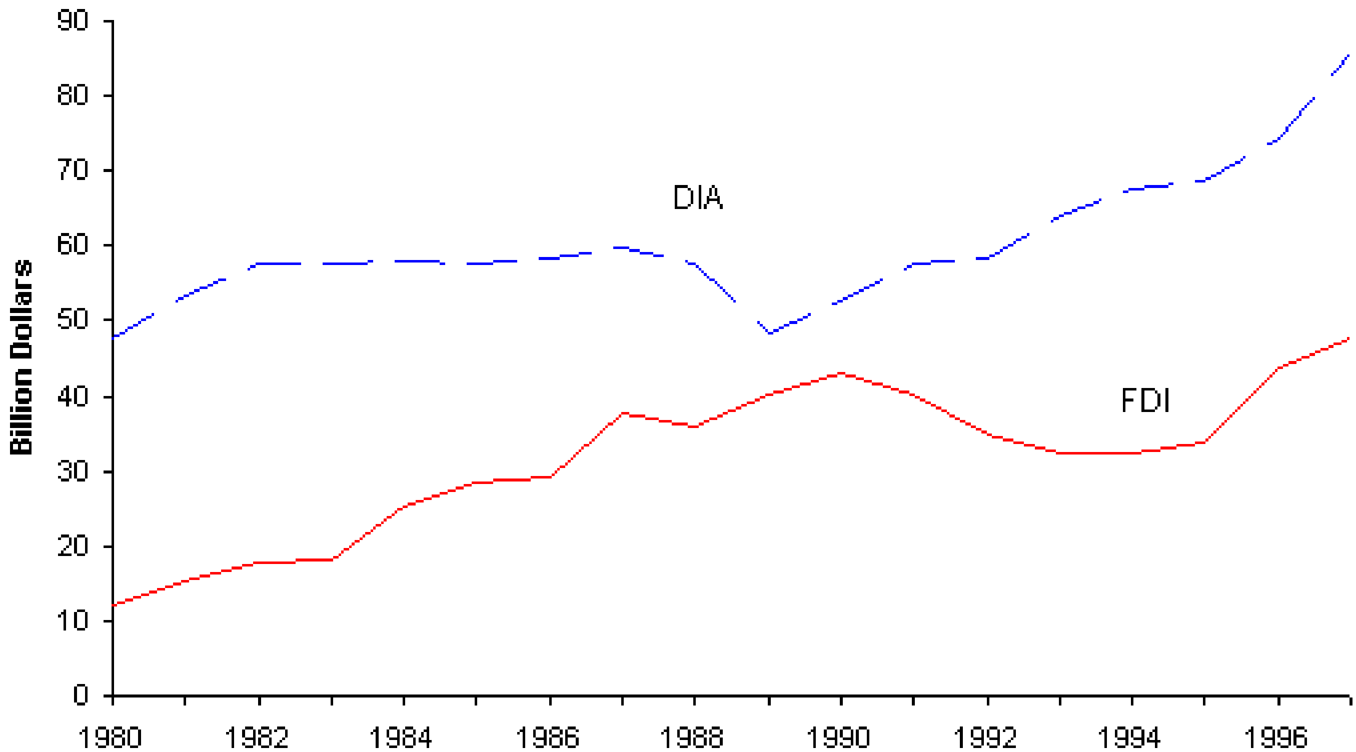
[a]Direct Investment Position Abroad is the value of U.S. parents' net equity in, and outstanding loans to, affiliates outside the United States.

[b]In 1998, the Bureau of Economic Analysis reclassified intercompany debt and associated interest transactions between parent companies and their affiliates that are nondepository financial intermediaries from direct investment to transactions with unaffiliated foreigners for the years 1994-1997. Thus there is a break between 1993 and 1994 in the Total U.S. Direct Investment Abroad and Petroleum as a Percent of Total series.

-- = not available; NM = not meaningful.

Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1998), Table 17, and preceding issues.

**Figure 30. U.S. Direct Investment Abroad Position in Petroleum and Foreign Direct Investment Position in U.S. Petroleum, 1980-1997**




Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, July 1998), Tables 3.1, 3.2, 4.1, and 4.2, and previous issues.

**Table 42.**
**U.S. Direct Investment Abroad Position in Petroleum and Natural Gas, by Selected Countries, 1995-1997**
(Million Dollars)

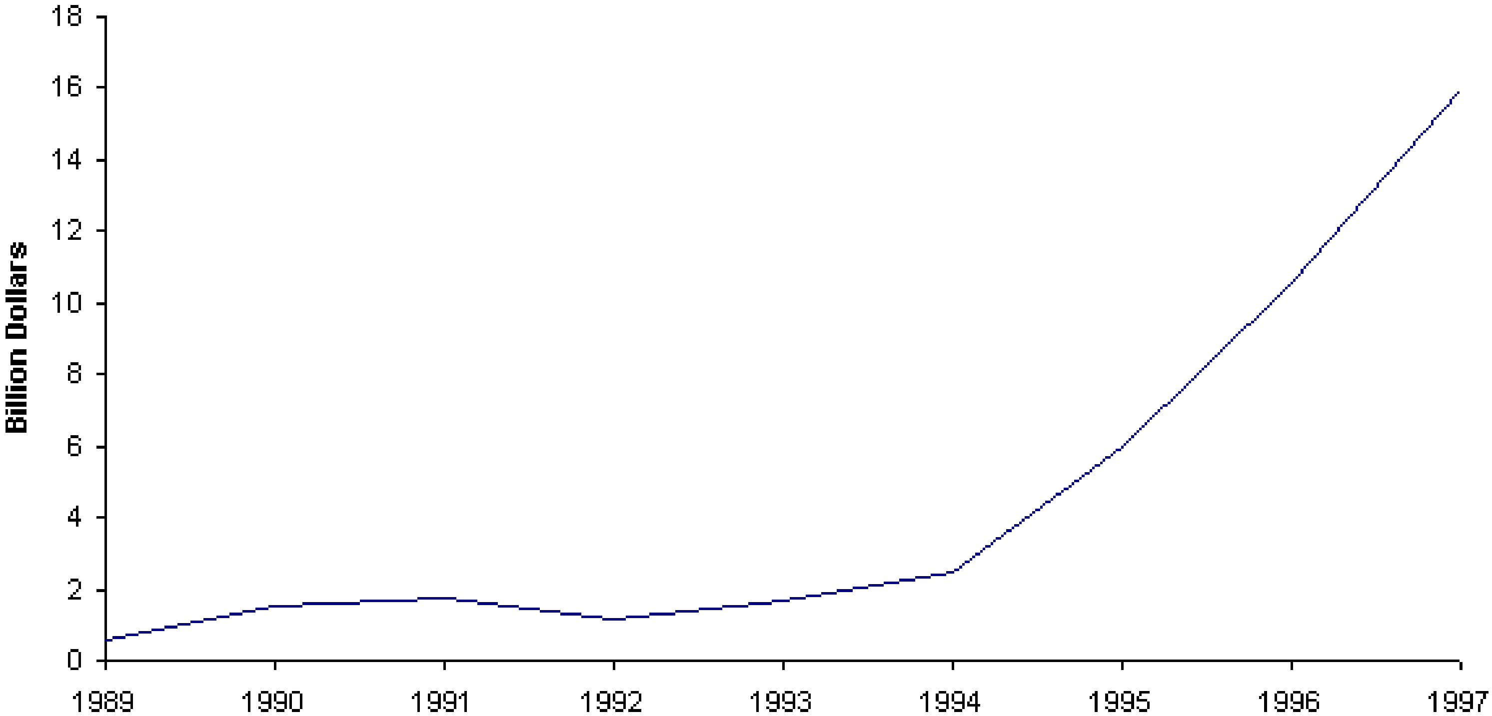
| Destination | U.S. Direct Investment Position Abroad | | | Net Additions | |
|---|---|---|---|---|---|
| | 1995 | 1996 | 1997 | 1996 | 1997 |
| All Countries | 68,639 | 74,499 | 85,726 | 5,860 | 11,227 |
| | | | | | |
| Canada | 9,875 | 11,331 | 12,738 | 1,456 | 1,407 |
| | | | | | |
| Europe | 23,603 | 27,153 | 29,793 | 3,550 | 2,640 |
| United Kingdom | 12,061 | 13,412 | 14,228 | 1,351 | 816 |
| Norway | 3,257 | 3,814 | 4,272 | 557 | 458 |
| | | | | | |
| Asia and Pacific | 20,792 | 19,187 | 20,442 | -1,605 | 1,255 |
| Indonesia | 4,449 | 4,387 | 4,768 | -62 | 381 |
| Japan | 6,040 | 4,385 | 4,686 | -1,655 | 301 |
| Singapore | 2,408 | 2,900 | 3,229 | 492 | 329 |
| | | | | | |
| Latin America and OWH[a] | 6,063 | 6,584 | 9,462 | 521 | 2,878 |
| Brazil | 1,092 | 1,116 | 1,769 | 24 | 653 |
| Argentina | 707 | 788 | 1,427 | 81 | 639 |
| Venezuela | 398 | 742 | 1,232 | 344 | 490 |
| Colombia | 1,255 | 1,172 | 1,120 | -83 | -52 |
| | | | | | |
| Africa | 3,193 | 3,616 | 5,872 | 423 | 2,256 |
| Nigeria | 578 | 549 | 1,373 | -29 | 824 |
| Egypt | 899 | 1,055 | 1,263 | 156 | 208 |

[a]Other Western Hemisphere

Source: Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, October 1998), Tables 10.2-10.4.

*Last Updated on 12/9/99*

**Figure 31. U.S. Direct Investment Abroad Position in Electric, Gas, and Sanitary Services, 1989-1997**




Sources: Bureau of Economic Analysis, "U.S. Direct Investment Abroad: Detail for Historical Cost Position and Related Capital and Income Flows, 1997," *Survey of Current Business* (Washington, DC, October 1998), Table 17, and preceding issues.

# Appendix A

# Structure of the Financial Reporting System - Form EIA-28

## Reporting Format

The FRS data system is designed to permit review of the functional performance of major energy-producing companies in total, as well as by specific functions and geographic areas of operation. The financial reporting schedules obtain data on revenues, costs, and profits, thereby indicating financial flows and performance characteristics. In addition, Form EIA-28 is used to collect balance sheet data (e.g., accumulated property, plant, and equipment), along with data on new investment in these accounts. To complement the financial data, statistical schedules are included to trace physical activity patterns and to evaluate several physical and financial relationships.

In greater detail, the structure of the reporting package is as follows:

1. Financial Reporting
   . The reporting begins with the three basic financial statements required by the Securities and Exchange Commission (SEC) Form 10-K:
      i. Consolidating Statement of Income (Schedule 5110)
      ii. Selected Consolidating Financial Data (Balance Sheets) (Schedule 5120)
      iii. Consolidated Statement of Cash Flows (Schedule 5131)
   b. Company-wide financial information is first disaggregated by functional lines (segments) on Schedules 5110 and 5120 as follows:
      i. Petroleum
      ii. Coal
      iii. Other Energy (includes Nuclear)
      iv. Nonenergy (includes Chemicals)
   c. Nonenergy data are collected to characterize corporate resource investment strategies and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.
2. Operating and Statistical Information
   . For each type of energy activity, complementary operating information is obtained through the following schedules:
      i. Petroleum (Schedule 5211-Schedule 5246)
      ii. Coal (Schedule 5341)
   b. The schedules are designed to correspond to the financial information so that the level of effort in the financial sense can be compared to physical results.
3. Complementary Schedules
   . Examine corporate research and development funding priorities (Schedule 5111)

b. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)
c. Monitor raw materials acquisition and refined product disposition strategies of FRS companies (Schedule 5211 and Schedule 5212)
d. Trace changes in reserves for petroleum (including natural gas) (Schedule 5246) and coal (Schedule 5341)

## Petroleum Segment Overview

The petroleum line of business is further disaggregated into segments.[122] These segments are presented as though each were a separate entity, with certain limitations, entering into transactions with other segments and third parties.

The following lists each segment within the petroleum line of business, along with a brief description of that segment's principal revenue-generating product or service. (Further detail on the FRS petroleum segments can be found in the section on *FRS Petroleum Supply and Trading Function* and *FRS Income Taxes*.)

1. *U.S. Production* - produces and sells U.S. crude oil, natural gas, and natural gas liquids. For FRS purposes, sales of U.S. crude oil must be made to the U.S. refining/marketing segment. Natural gas and natural gas liquids can be purchased from or sold directly to U.S. or foreign third parties, unconsolidated affiliates, and other U.S. or foreign segments.
2. *U.S. Refining/Marketing* - purchases raw materials from the U.S. production segment, the foreign refining/marketing segment, and third parties for refining or sale to third parties. The segment also purchases directly from the foreign production segment for those companies that do not have foreign refining/marketing and import all foreign production and purchases.
3. *U.S. Pipelines* - transport crude oil, natural gas, and natural gas liquids through Federal-or State-regulated pipeline operations.
4. *Foreign Production* - produces and sells foreign crude oil, natural gas, and natural gas liquids. Crude oil sales are made to the foreign refining/marketing segment unless the company does not have foreign refinery operations and imports all foreign crude oil gained through production or purchases. Companies that meet these criteria may sell directly to the U.S. refining/marketing segment.
5. *Foreign Refining/Marketing* - purchases raw materials from foreign production segments and U.S. refining/marketing segments, refines, and sells to third parties and refining/marketing segments.
6. *International Marine* - provides marine transportation of foreign and U.S. source crude oil.

## Selection of FRS Reporting Companies

From 1977 through 1997, companies were selected if they were U.S.-based publicly-owned companies or U.S.-based subsidiaries of publicly-owned foreign companies within the top 50 publicly-owned U.S. crude oil producers that had at least 1 percent of either production or reserves of oil, gas, coal, or uranium in the United States, or 1 percent of either refining capacity or petroleum product sales in the United States. After 1997, companies were selected if they were U.S.-based publicly-owned companies or U.S.-based subsidiaries of publicly-owned foreign companies that had at least 1 percent of either production of reserves of oil or gas in the United States, or 1 percent of either refining capacity or petroleum product sales in the United States.

Mergers, acquisitions, and spinoffs, together with the applications of the selection criteria, resulted in the list of FRS reporting companies shown in Table A1

.

# Data Quality Assurance Program

The data quality assurance program encompasses EIA's efforts to ensure the quality and integrity of FRS data. These efforts are evidenced by the design of the form and by the procedures applied to verify the data, including computer programmed checks and desk review procedures.

## Forms Design

The Securities and Exchange Commission (SEC) Form 10-K contains financial statements audited by independent certified public accountants. These financial statements and the entire text of the annual report and Form 10-K are

reviewed by the SEC staff to provide the investing public with assurances that data filed on Form 10-K are accurate and are in accordance with generally accepted accounting principles and SEC Regulations.

The FRS Form EIA-28 is designed in a multi-tier structure to take advantage of the SEC review and audit by independent certified public accountants. This structure presents both the Form 10-K figures and statistics and the more detailed data required by the FRS system. The top FRS tier corresponds to Form 10-K; the second tier is the first tier disaggregated into the different sources of energy (e.g., petroleum, coal); and the third tier is the second tier disaggregated into the specific functional line-of-business segments within petroleum. (See the Petroleum Segment Overview section at the beginning of this appendix which describes the FRS segments in detail.) The fourth tier provides further detail within the individual segments- for example, the details of petroleum raw materials purchased and sold. Therefore, the lower tiers can be aggregated to each successively higher tier until the consolidated Form 10-K figures are reached. In this way, the more detailed FRS data is tied to the aggregated figures already reported publicly to the SEC and to company shareholders.

## Review Procedures

Detailed computer editing and desk review procedures have been established for the incoming FRS data. The result of each review is the issuance of a letter to the reporting company containing questions regarding data elements. The reporting companies respond to each question, either by explaining the item or by amending any incorrect schedule. Amended schedules are reprocessed like the original, with the full range of desk and computer checks. The result of this process is an internally consistent database that has been reconciled to the Form 10-K and from which the output reports can be compiled.

The FRS review procedures include:

- Computer programmed checks for mathematical accuracy (e.g., addition and subtraction)
- Computer programmed checks to insure that corresponding schedules are correctly

cross-referenced

- Desk reviews comparing reported FRS data to information from each company's Form 10-K and annual report
- Desk reviews comparing reported data (e.g., average cost per foot drilled) for an individual FRS company to the average for all FRS reporting companies and to prior year information of the individual company
- Desk reviews comparing reported data to other related data series to ascertain any unusual variance
- Statistical disclosure avoidance procedures.

## Computer Programmed Checks

There are 808 computer programmed checks for mathematical accuracy which ensure that each horizontal and vertical total equals the sum of the amounts within each line or column. There are also 51 computer programmed cross-reference checks which ascertain that the amounts within a certain section of a schedule equal the amounts of the same description within a different schedule. The cross-reference checks are performed to ensure accuracy and consistency between different schedules. For example, the amount reported on Schedule 5210 for the U.S. production segment charges for depreciation, depletion, and amortization is cross-referenced to ensure the same amount is reported on Schedule 5120. Since the number and type of errors noted during these checks is an indicator of respondent understanding of the form, existing and potential problems are identified. The FRS review staff can then focus most of their attention on specific companies and areas where data accuracy may be of a greater concern.

## Desk Review Procedures

Desk review procedures encompass a detailed comparison of the data submitted to information contained in the Form 10-K and the annual report to company shareholders, as well as other publicly available information.

As stated previously, the Form 10-K and the annual report contain financial information audited by independent certified public accountants. This financial information, along with textual and statistical information, has also been reviewed by the SEC staff, which includes not only accountants, lawyers, and financial analysts, but also petroleum and mineral resource engineers. Hence, the data contained in these documents is considered a valuable reference in connection with the quality of FRS data.

The data contained in each respondent's submission is compared to the data on Form 10-K and the annual report material by use of a detailed review program. Each review program step is performed by trained auditors supervised by CPAs with experience in auditing medium-to-large public companies.

These comparisons involve checking elements in both the financial and physical information areas (e.g., production, reserves, refinery statistics, etc.). Direct comparisons are made of specific data elements from the FRS form with corresponding items on Form 10-K or in the annual report. Indirect comparisons deal with information that is mentioned in Form 10-K and the annual report, but which is not quantified sufficiently for direct matching with FRS data. For example, if a respondent's annual report discussed an investment in coal, appropriate entries would be expected on the FRS schedule for coal.

The FRS desk review procedures also include two other types of comparisons. The first type of comparison is made against prior year FRS data of the reporting company as well as the average data for all FRS reporting companies. These procedures ensure consistency and reasonableness across reporting years.

The second procedure involves comparing data to other related data series. Information contained in the FRS system is compared to data available from other DOE systems and published data, such as state mining surveys.

The FRS desk review procedures described above often lead to the formulation of a set of questions that are issued to the reporting companies each year. Response to these questions generates substantial interchange between the energy company staffs and the FRS staff. From this interchange the company personnel acquire a better understanding of the unique aspects of the FRS system. The FRS staff learns more about each reporting company, the industry, and how each company's accounting and reporting practices might affect the published FRS aggregate data.

### Statistical Disclosure Avoidance Procedures

Procedures to prevent the disclosure of "individually identifiable energy information" have been applied to each table in this report. These tables provide summary rather than company-specific information. In most cases, the level of summarization applies to all FRS companies. In certain cases, subcategories have been established that break the reports into size or other descriptive classes. Each table has been screened to ensure that no statistical disclosure will occur.

A large number of summary computer reports, generated from a single selected database, provide the basis for these tables. In conjunction with the summary reports, a parallel set of cell count reports were produced that tabulate for each report cell the number of nonzero values that were aggregated to produce the summary value. The cell count reports were then reviewed to identify whether potential disclosure problems would result from having an insufficient number of reporters or from having values that represent primarily dominant companies in a particular energy sector or activity.

If potential disclosure problems are identified, the tables are restructured to combine values or groups of individual cells in the tables so that the resulting tables are essentially disclosure free.

## Financial Analysis Guide

### Indicators of Financial Performance

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected to show the amounts and geographic distribution of production, profits, cash generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same as, or similar, to indicators that have been in regular use by financial analysts and economists for many years.

However, to avoid potential misunderstandings, the measures used, their significance, and their limitations are described below.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on Generally Accepted Accounting Principles (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations, cash flows, and financial positions of individual business enterprises. The two primary issues one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions and market values are not reflected). Both of these can cause a degree of noncomparability of reported data across companies in the case of accounting methods and through time in the case of historical cost accounting. In spite of these problems, the data are regarded as meaningful, especially for trend analysis. (For a further discussion of these two problems, see the Accounting Practices section of this appendix.)

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP, this measure is based on arm's-length transactions with third parties. However, in the FRS system, the concept of sales has been extended to include sales from one segment to another. By use of such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation. The establishment of the FRS segments, the definition of sales (trading function), and the nontraceable and eliminations categories are discussed more fully in the Accounting Practices section of this appendix.

Profits are the measure of financial return for company activities. In the FRS system, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits and represents income after the provision for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Excluded from this figure are such items as income taxes, interest income, and interest expense, which are not allocated to the segments because they are "corporate-level" items for FRS system purposes. (This is explained more fully in the Accounting Practices section of this appendix.) Contribution to net income is meant to be the equivalent of net income for individual segments and excludes several corporate-level items which are not allocated to the segment level.

"Cash flow from operations" is presented for the consolidated company. It generally follows the indirect or reconciliation method of reporting cash flow from operations allowed by Statement of Financial Accounting Standards No. 95. The indirect method adjusts net income to remove the effects of changes in receivables, payables, and inventory during the year. The indirect method also adjusts for the effects of depreciation, depletion, and amortization, gains or losses on disposition of property, plant, and equipment, and other items.

"Cash flow from operations" represents the cash effects of producing and delivering the company's products and services. This presentation is useful in analyzing the ability to generate future positive cash flow, adequacy of cash flow in relation to current obligations, and the relationship of net income to cash flow.

Accumulated investment is expressed by: (1) total assets; (2) net property, plant, and equipment (PP&E); (3) investments and advances to unconsolidated affiliates; and (4) net investment in place.

Total assets are used in the context of the consolidated company figures and are the total of the left-hand, or asset side, of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates are of interest because many energy companies extend the range of their activities through subsidiaries of which they own less than 50 percent.

Finally, net investment in place is the total of: (1) net PP&E and (2) investments and advances to unconsolidated affiliates.

Annual new investment is the measure of newly committed resources during any given year. In the FRS system, this is expressed in terms of: (1) additions to PP&E; (2) current capitalized exploration and development (E&D) expenditures; (3) current expenditures on E&D; (4) additions to investment in unconsolidated affiliates; and (5) additions to net investment in place. The key words are: *current*, which means simply a current commitment of resources; and *capitalized*, which refers to expenditures that are classified as an addition to the PP&E account in the balance sheet rather than as an expense of the current year in the income statement. Being capitalized indicates that the expenditure benefits future years and will be amortized to expense in the years benefitted. Being expensed means the cost does not directly benefit a future period; therefore, the cost should be shown as an expense of the current year. The capitalization concept is at the heart of the difference between the successful efforts versus full cost accounting methods (discussed in the Accounting Practices section of this appendix). Therefore, in the FRS system, total expenditures that are both expensed and capitalized are used as a measure of activity to standardize the measurement of resources invested.

### Foreign Reserve Interests

This category includes all three types of foreign reserves collected on Form EIA-28: (1) net ownership interest reserves; (2) proportionate interest in investee reserves; and (3) foreign access reserves. These three foreign categories are added together for purposes of comparison with U.S. net working interest reserves because of the different nature of company interests in foreign production as compared to U.S. production.

Foreign petroleum reserve statistics are not strictly comparable to those of U.S. petroleum reserves because of the more complex and varying arrangements whereby U.S. companies obtain foreign crude oil. In addition, such arrangements have been known to be changed suddenly by those governments, thereby imposing a degree of uncertainty about what a reporting company can describe as its equity reserves. Foreign reserve statistics may be used as an indicator of the rate and magnitude of industry activity, but the fact that their character is distinct from those of U.S. reserves must be recognized.

## Accounting Practices

### Relation of FRS to Generally Accepted Accounting Principles

In completing Form EIA-28, with one exception noted below, companies use the same generally accepted accounting principles that they use in their financial statements filed with the SEC and in their annual reports to shareholders. Therefore, the amount and timing of income recognized and the capitalization policies will be the same. Net income in the FRS system will agree in total with that reported in each company's financial statements.

However, in the FRS system the presentation of the details of financial and statistical data will usually differ somewhat from that presented by most individual companies because current reporting standards do not require standardized business segments with standardized financial statement line items. In the

FRS system, such standardization is necessary because of the need to aggregate a large number of companies (see Sec. 205(h), P.L. 95-91).

## FRS Petroleum Supply and Trading Function

In establishing the FRS functional lines of business for reporting the activities of vertically integrated enterprises, it was necessary to define a set of trading rules. Each segment can engage in activities as defined by the rules. Otherwise, the segment data would be inconsistent between companies.

FRS defines the following segments within petroleum; they are the main components of the 5200 series schedules:

- U.S. Production
- U.S. Refining/Marketing
- U.S. Pipelines
- Foreign Production
- Foreign Refining/Marketing
- International Marine (Transportation).
-

A few of the more noteworthy rules, intended to make the trading activities of each FRS reporting company comparable to those of the other companies, are as follows:

1. Transfers (sales) between segments of the same company are recorded at arm's-length market prices. Where there are no comparable arm's-length transactions, field posted prices may be used. If third party realizations for specific raw material streams are below posted prices, the same lower prices should be used to value internal transfers of those raw materials.
2. All crude oil produced is recorded as a sale by the respective foreign or U.S. production segments to the corresponding foreign or U.S. refining/marketing segments. The production segments are not permitted to sell crude oil directly to third parties, but instead must transfer it to the company's refining/marketing segments which sell, in turn, to the third parties. Companies that do not have foreign refining and import all foreign purchases may deviate from this practice and sell directly to U.S. refining/marketing.
3. Crude oil purchased from third parties is reflected as a purchase by the appropriate refining/marketing segment: foreign refining/marketing for foreign source crude oil and U.S. refining/marketing for U.S. source crude oil. Foreign source crude oil destined for a U.S. refining segment is then recorded as a sale by the foreign refining/marketing segment to the U.S. refining/marketing segment.
4. Although production segments are neither sellers nor purchasers of crude oil from third parties, by FRS system convention, natural gas may be both purchased and sold by production segments.
5. All transportation costs are incurred by the purchasing segment. Therefore, when U.S. refining/marketing segments purchase crude oil from foreign refining/marketing segments, the U.S. refining/marketing segment incurs the transportation cost.
6. With regard to sales to third parties, an export sale is a sale shipped free on board (f.o.b.) to a foreign location. In contrast, if a sale is made f.o.b. to a U.S. location, it is considered a U.S. sale even though the goods may ultimately be shipped overseas by a third party who purchased the

goods.

7. A U.S. purchase is a purchase made from U.S. sources, even though, in the case of goods purchased from third parties, the materials purchased may be of foreign origin. In the FRS system, the point of purchase and not the country of production is the determining factor.

## Nontraceables and Eliminations

One of the objectives of the FRS system is to allow economic and financial analysis of the energy industry to be performed by individual functions. These functions, referred to in the FRS system as segments, are presented as separate entities with their own income statements. They reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments.

The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The second is the eliminations classification, which prevents double counting of intersegment transactions when the segments are consolidated into total company figures.

The nontraceable classification captures assets, liabilities, revenues, and expense items that cannot be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm, as well as financial activities which represent corporate-level activities.

While the financial transactions may play a key role in the firm's ability to do business, such transactions are not allocated to activities in an individual segment. Cash, corporate investments, interest income, and interest expense are examples of nontraceable items. The accompanying example illustrates a nontraceable item, interest expense of $20, and the $10 corresponding tax effect ( see "FRS Segment Tax Allocation Rules" in this appendix for further explanation).

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which, in turn, sells the product again. In the example illustrated in Table A2, $80 of crude oil is sold by the U.S. production segment to the refining/marketing segment. The refining/marketing segment records $80 of purchases of crude oil and, after processing, reflects sales of $160 of refined product. If the segment figures were simply added to arrive at the consolidated total, the consolidated sales figure of $240 ($80 + $160) would be too high because of double counting. Thus, the eliminations classification subtracts $80 of sales and $80 of costs, leaving consolidated sales of $160, the appropriate measure of the firm's consolidated transactions.

The nontraceables and eliminations classifications are treated as if they are segments for purposes of aggregating segment data to the consolidated level.

## FRS Income Taxes

***FRS Segment Tax Allocation Rules.*** In the FRS system, the tax allocated to each segment reflects a pro-rata share of consolidated income taxes. Where the consolidated company reports income and pays a tax, but an individual segment incurs a loss, the segment with a loss reflects a tax benefit. This treatment is an FRS rule whose purpose is to reflect, at the segment level, the effect of the segment's operations on the consolidated income taxes. The tax benefit reflected at the segment level is limited to the extent it offsets taxes in other segments on a consolidated basis. In comparing an FRS company's segment to a specialized (nonintegrated) company in the same line of business, one must consider the effect of the above described rule. The current tax effect may be different, since a specialized company cannot report tax benefits for operating losses incurred in that year. It must carry the loss forward, or backward, against profits of other years, while a segment of an otherwise profitable consolidated firm can show a tax benefit by FRS conventions because a segment's loss can offset profits in other segments on a consolidated basis.

***FRS Reporting Companies, Segments, and Tax-Paying Entities.*** FRS reporting companies and their segments differ from the entities which actually pay income taxes. The FRS system reports energy activities on a consolidated company basis, disaggregated into various energy lines of business. Accordingly, income tax expense, current and deferred, is reflected on a line-of-business basis. However, under the tax laws, taxes are not necessarily based upon FRS reporting company consolidated earnings of the FRS line-of-business segments.

The tax-paying entities of an FRS reporting company are its subsidiaries. Some are incorporated in the United States and some in foreign countries, and each may operate in the United States, foreign countries, or both. Income tax expense in the FRS system consists of both U.S. and foreign income taxes incurred by these subsidiaries. Taxes reflected by the consolidated company and each individual segment are allocated from taxes paid and deferred by the actual tax-paying entities.

The United States taxes only income of foreign corporations earned in the United States or paid into the United States as dividends to a U.S. parent corporation (owner). All income subject to U.S. tax, whether the entity is a foreign or U.S. corporation, is given the benefit of the foreign income tax credit (up to the statutory rate) to avoid double taxation. Each U.S. incorporated subsidiary of a U.S. corporation elects either to be included in a consolidated U.S. tax return or to file a separate return, depending on which election is most likely to minimize the aggregate U.S. and foreign taxes. In the FRS system, corporate organization and relationships are not purely a function of line-of-business financial reporting. This fact requires that allocations be made of taxes incurred so that they can be classified according to the FRS segment format. These allocations are required when a subsidiary is involved in both U.S. and foreign operations and/or in more than one line of energy business. For example, the FRS system has separate segments for the foreign and U.S. petroleum production business, and for the foreign and U.S. refining/marketing business. Therefore, if an FRS reporting company has a foreign subsidiary involved in both petroleum production and refining/marketing of petroleum, a disaggregation of that subsidiary's activities, including income taxes, must be made.

The disaggregation is further complicated by the existence of nontraceable items, such as interest expense, interest income, minority interest, and foreign currency gains and losses. The nontraceable column must be treated as a separate segment when the tax allocation is made.

## Deferred Taxes

The Financial Accounting Standards Board (FASB) began working on a project to reexamine the generally accepted accounting procedure for income taxes in September 1982. Accounting Principles Board Opinion 11 ("APB 11"), issued in 1967, faced criticism and concerns about the inconsistencies in its amendments and interpretations. In addition, problems created by new tax depreciation methods and changes in accounting for income taxes in other countries were making APB 11 outdated. In 1988, the

FASB issued Statement of Financial Accounting Standards No. 96, "Accounting for Income Taxes" ("SFAS 96"), to address the increased complexity and significance of deferred taxes in the balance sheet. However, because of its complex scheduling process and conservative tax asset provisions, SFAS 96 soon became a source of controversy among businesses, CPA firms, professional organizations, and industry trade groups. In response to the criticism, the FASB deferred the required implementation date of SFAS 96 three times (SFAS 100, 103, and 108) and began developing a new standard which would address not only criticism of APB Opinion 11 but also the controversy surrounding SFAS 96. The new standard, SFAS 109, "Accounting for Income Taxes," became effective for periods beginning after December 15, 1992.

The objective of accounting for income taxes is the recognition and presentation in the financial statements of the following:

- Taxes currently payable or refundable
- Deferred tax assets and liabilities for the future tax consequences of events that have been recognized in the financial statements or tax returns.

Deferred taxes reflect the future tax consequences of events already recognized in either the financial statements or tax returns. SFAS 109 uses the balance sheet approach, also referred to as the liability method, to determine deferred taxes. This method, first introduced in SFAS 96, differs from APB 11, which used the income statement approach. SFAS 109 also requires a deferred tax asset to be recognized for deductible temporary differences and operating loss and tax credit carryforwards using the applicable tax rate.

The income statement approach recognizes deferred taxes on the temporary timing differences between pretax accounting income and taxable income each year. Temporary differences are those differences between accounting and taxable income that will ultimately reverse. For example, intangible drilling costs for a successful well are expensed when paid for tax purposes but capitalized and depreciated for accounting purposes. If we assume the intangible drilling cost of $100,000 was the sole timing difference, and this cost was depreciated $20,000 per year for accounting purposes, there would be an $80,000 temporary timing difference in year one, as taxable income would be less than accounting income. This timing difference would reverse $20,000 each year as the intangible drilling cost is depreciated for accounting purposes with no deduction for tax purposes. At the end of the fifth year, the timing difference would be completely reversed.

The liability approach recognizes deferred taxes on the temporary differences between the financial and tax bases of assets and liabilities. Both the deferred tax liability and the deferred tax asset must be measured by use of the applicable tax rate. The applicable tax rate is the enacted tax rate to be applied to the last dollar of taxable income for the year when the liability is expected to be settled or the assets recovered. A single flat tax rate may be used for companies for which graduated rates are not a significant factor. A deferred tax asset is recognized for existing alternative minimum tax credit carryforwards for tax purposes. When computing deferred tax assets and/or liabilities, if there is a change in the tax rate or tax law, the deferred tax assets and/or liabilities should be adjusted in the period that includes the enactment date. To the extent deferred tax balances are adjusted for the effects of such changes, income tax expense or benefit from continuing operations is charged or credited. Using the example from the preceding paragraph, the financial statement basis of the intangible drilling cost in year one would be $80,000 ($100,000 less $20,000 depreciation), while there would be no basis for tax purposes because the costs were totally deducted. Deferred taxes would be provided for the $80,000 difference by use of enacted tax rates. Deferred taxes would be adjusted each year until the difference between the financial accounting and tax bases was fully eliminated at the end of year five.

Once deferred tax assets and liabilities relating to the future tax consequences of temporary differences and carryforwards have been measured, the deferred tax provision or benefit is based on the net change in a deferred tax balance during the year. The income tax expense or benefit for the period is derived from the total tax currently payable or refundable and the deferred tax expense or benefit.

As stated earlier, SFAS 109 became effective for fiscal years beginning after December 15, 1992. There were two transition options available when adopting SFAS 109: prospective or retroactive application. A company could elect to restate the financial statements for any number of consecutive prior years (retroactive application) or report a cumulative effect adjustment below "income from continuing operations" (prospective application).

For 1993 through 1997, all FRS companies have reported taxes in accordance with SFAS 109. For 1992, seventeen FRS reporting companies had adopted the provisions of SFAS 109, which resulted in a net $163 million benefit to their 1992 reported earnings. The remaining eight FRS reporting companies adopted SFAS 109 in the first quarter of 1993, resulting in a $671 million benefit to 1993 reported earnings. Of the eight companies which had not adopted SFAS 109 in 1992, five reported under APB 11 and three reported in accordance with SFAS 96.

### Corporate Acquisitions

Under FRS reporting rules, no acquisitions are accounted for under the pooling of interest method. This is because, under the pooling method, the financial statements do not reflect such transactions as new investment, since the historical financial statements are restated. One of the objectives of the FRS is to track new investment activities.

For FRS reporting purposes, acquisitions accounted for as pooling for annual report purposes must be reflected in the FRS filing under a modified purchase method. Allpurchase accounting rules are followed, except that the assets of the acquired company are not revalued but are recorded at their book values as stated on the acquired company's books.

### Full Cost and Successful Efforts Accounting Methods

FRS reporting companies are permitted to choose between two accounting methods, "full cost" and "successful efforts," to account for their exploration and production activities. All but two of the FRS companies use the successful efforts method. The main difference between the two methods is the treatment of dry exploratory well cost.

Under full cost, the cost of a dry exploratory well is capitalized and then amortized to the income statement over the productive life of successful wells. Thus, the costs of both dry and successful wells are capitalized and reflected in the balance sheet as part of producing properties.

Under successful efforts, the cost of a dry exploratory well is written off to expense in the year in which drilling is determined to be unsuccessful. There is no capitalized cost of such dry exploratory wells carried on the balance sheet.

In comparison to the successful efforts method, the full cost method will: (1) show less volatility of earnings, since the cost of unsuccessful wells is amortized over many years; (2) show a higher balance in accumulated property, plant, and equipment (PP&E), since the account contains the costs of all wells drilled, including dry exploratory wells; (3) usually show higher earnings during years of intense exploratory activity when a number of dry wells are encountered; and (4) show the same cumulative earnings over a long period of years, since eventually all costs will be amortized to the income statement. These effects are minimized if the firm is large, since the exploratory activities of a large firm are usually smaller, relative to total production operations, than they are in a small production firm.

Usually, the precise effect of using one method over the other cannot be determined. However, one large firm switched from full cost to successful efforts in 1975 and restated 1973 and 1974 data to the successful efforts method. Thus, we have available the impact of this conversion on their comparative net income, net PP&E, and return on net PP&E for 1973 and 1974 (see Table A3). Since twenty-two of the FRS companies presently use successful efforts accounting, comparability problems are inconsequential.

## Inventory Accounting - LIFO Versus FIFO

The Last In-First Out (LIFO) and the First In-First Out (FIFO) inventory methods are used most often in the preparation of financial statements of industrial enterprises.

Under FIFO, the balance sheet valuation of inventory is based upon the most recent prices paid for the physical units on hand at year's end, and the income statement reflects the cost of units sold at the oldest unit cost. In periods of rapidly rising prices, the income statement reflects higher profits than would be reflected if the units sold were priced at current replacement cost or under the LIFO method.

Under LIFO, the balance sheet valuation of inventory is based on the prices paid for the first units of each major type of inventory ever purchased. For example, crude oil could be carried at $10 per barrel, an amount which vastly understates the value of the inventory in terms of its replacement cost. The income statement reflects the cost of units sold at the most recent prices paid for the number of units sold. Thus, cost of goods sold reflects nearly a replacement cost amount, and profits are lower than under the FIFO method.

Since either method is permitted under the Federal tax laws, most companies use LIFO for operations subject to U.S. taxation because earnings and, hence, taxes are lower under this method. By 1979, most FRS reporting companies were using primarily the LIFO inventory method. Most analysts probably would agree that LIFO is the preferable method, since the income statement is more realistic than with FIFO. However, its disadvantage is that the balance sheet's inventory figure is understated, and, hence, the stockholders' equity amount is correspondingly understated.

In 1997, three FRS companies reported liquidation profits or losses. The 1997 aggregate liquidation profits increased the reporting companies' operating income by $99 million, an amount which represented 0.2 percent of their aggregate operating income. This compares to a $46 million increase in 1996 and a $163 million increase in 1995, amounts that represented 0.1 and 0.5 percent, respectively, of aggregate operating income for each year.

## Foreign Currency Translations

In December 1981, the Financial Accounting Standards Board (FASB) issued Statement No. 52, "Foreign Currency Translations," which superseded FASB-8, "Accounting for the Translation of Foreign Currency Transactions and Foreign Currency Financial Statements." FASB-52 covers the translation of foreign currency financial statements for the purposes of the consolidation, combination, or reporting by the equity method and the translation of foreign currency transactions. The new statement required that assets, liabilities, and operations of an entity be stated in the currency of the primary economic environment in which the entity operates (termed the "functional currency"). If a foreign entity has not kept its financial records in the functional currency, remeasurement is required prior to translation. Any gain or loss on remeasurement is recognized in current net income. The assets and liabilities of the foreign entity are translated from its functional currency to the reporting currency at the current rate of exchange.

Under FASB-52, gain or loss on the translation of foreign currency financial statements is shown as a separate component of stockholders' equity, whereas, under FASB-8, all non-monetary balance sheet items were translated at the historical rate of exchange. Thus, the change to FASB-52, which uses the current rate of exchange, had the most significant impact on inventories and fixed assets. With respect to the income statement, FASB-52 requires that only gains or losses from foreign currency transactions be included.

As Table A4 indicates, foreign currency translation gains decreased stockholders' equity by 2.0 percent, while foreign currency transaction losses decreased pretax income by 0.5 percent in 1997.

## FRS Database History

The Form EIA-28, "Financial Reporting System (FRS)," database has existed in three formats during its 22-year history. In addition, there have been minor, periodic adjustments since 1987. The most noteworthy was the change from a Statement of Sources and Uses of Funds to a Statement of Cash Flows, effective in the 1986 reporting year. The first version of the Form EIA-28 and its database covered years 1974-1980. The second version covered years 1981-1986. The third covered years 1987-1992. The fourth version begins with the 1993 reporting year and is approved through the 1999 reporting year.

The current version was changed by the addition of the former Soviet Union and Eastern Europe as a new geographical reporting area.

The first full reporting year for the first version of the form was 1977. It consisted of 47 separate schedules containing 8,775 data elements and was 136 pages long.[123] This version of the database contained a significant amount of detail at the consolidated level, in each line of business and in the breadth of operating statistics. However, not all of the collected data were loaded into the database. About 1,000 elements were not unique to individual companies-such as joint venture information-and were maintained only in their hard copy format.

In 1982 (for the 1981 reporting year), the form was shortened by 72 percent, to 2,468 elements. The format was still the same, with data collected at the consolidated level, four energy lines of business (petroleum, coal, nuclear, and other energy) and nonenergy. The 1981-1986 form consisted of 19 schedules and was 35 pages long. Although data were still collected by each line of business, most of the decline was at the line-of-business level, where more than 81 percent of the form was eliminated, compared with a 58-percent decline at the consolidated level.

In 1988 (for the 1987 reporting year), the form was shortened by another 33 percent, to 1,650 elements. The consolidated level was shortened by 32 percent, primarily by combining other energy with nuclear energy. Petroleum data declined by 10 percent, coal by 74 percent, and separate income statement schedules for the remaining lines of business (coal, nuclear and other energy, and nonenergy) were eliminated altogether (although income statements for each of these lines of business were incorporated into Schedule 5110, Consolidating Statement of Income). The form currently has 14 schedules and is 27 pages long.

## Appendix A Endnotes

122 The other lines of business (Coal, Other Energy, and Nonenergy) were also disaggregated into segments, but only through 1986.

123 In order to extend the range of the data back through 1974, an abbreviated version of the form was collected for the years 1974 through 1976. Almost 2,900 data elements (one-third of the total) were collected for each of these years, and consisted primarily of summary data from 26 of the 47 schedules.

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# Table A1. Companies Reporting to the Financial Reporting System, 1974-1998

| Company | 1974-81 | 1982 | 1983-84 | 1985-86 | 1987 | 1988 | 1989-90 | 1991 | 1992-93 | 1994-96 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| Amerada Hess Corporation | X | X | X | X | X | X | X | X | X | X | X | X |
| American Petrofina, Inc.[a] | X | X | X | X | X | X | X | | | | | |
| Amoco Corporation[b c] | X | X | X | X | X | X | X | X | X | X | X | X |
| Anadarko Petroleum Corporation | | | | | | | | X | X | X | | X |
| Ashland Inc. [d] | X | X | X | X | X | X | X | X | X | X | X | |
| Atlantic Richfield Co. (ARCO) | X | X | X | X | X | X | X | X | X | X | X | X |
| BP America, Inc.[c e] | | | | | X | X | X | X | X | X | X | X |
| Burlington Northern Inc.[f] | X | X | X | X | X | | | | | | | |
| Burlington Resources Inc.[f] | | | | | | X | X | X | X | X | X | X |
| Chevron Corporation[g h] | X | X | X | X | X | X | X | X | X | X | X | X |
| Citgo Petroleum Corporation | | | | | | | | | | | | X |
| Cities Service[i] | X | X | | | | | | | | | | |
| Clark Refining and Marketing, Inc. | | | | | | | | | | | | X |
| The Coastal Corporation | X | X | X | X | X | X | X | X | X | X | X | X |
| Conoco [j k] | X | | | | | | | | | | | X |
| E.I. du Pont de Nemours and Co.[j k] | | X | X | X | X | X | X | X | X | X | X | |
| Enron Corp. | | | | | | | | | X | X | X | X |
| Equilon Enterprises, LLC [l] | | | | | | | | | | | | X |
| Exxon Corporation [m] | X | X | X | X | X | X | X | X | X | X | X | X |
| Fina, Inc.[a] | | | | | | | | X | X | X | X | X |
| Getty Oil[n] | X | X | X | | | | | | | | | |
| Gulf Oil[h] | X | X | X | | | | | | | | | |
| Kerr-McGee Corporation [o] | X | X | X | X | X | X | X | X | X | X | X | X |
| LYONDELL-CITGO Refining, LP [p] | | | | | | | | | | | | X |
| Marathon [q] | X | | | | | | | | | | | |
| Mobil Corporation [m r] | X | X | X | X | X | X | X | X | X | X | X | X |
| Motiva Enterprises LLC [s] | | | | | | | | | | | | X |
| Nerco, Inc.[t] | | | | | | | | | X | | | |
| Occidental Petroleum Corporation[i] | X | X | X | X | X | X | X | X | X | X | X | X |
| Oryx Energy Company[o u] | | | | | | X | X | X | X | X | X | |
| Phillips Petroleum Company | X | X | X | X | X | X | X | X | X | X | X | X |
| Shell Oil Company | X | X | X | X | X | X | X | X | X | X | X | X |
| Sonat Inc. | | | | | | | | | | | X | X |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Standard Oil Co. (Ohio) (SOHIO)[e] | X | X | X | X | | | | | | | | |
| Sun Company, Inc.[u] [v] | X | X | X | X | X | X | X | X | X | X | | X |
| Superior Oil[r] | X | X | X | | | | | | | | | |
| Tenneco Inc.[w] | X | X | X | X | X | X | | | | | | |
| Tesoro Petroleum Corporation | | | | | | | | | | | | X |
| Texaco Inc.[n] | X | X | X | X | X | X | X | X | X | X | X | X |
| Tosco Corporation | | | | | | | | | | | | X |
| Total Petroleum (North America) Ltd.[x] | | | | | | | X | X | | | | |
| Ultramar Diamond Shamrock Corp. | | | | | | | | | | | X | |
| Union Pacific Resources Group, Inc. | Inc. [y] | X | X | X | X | X | X | X | X | X | X | X |
| Unocal Corporation | X | X | X | X | X | X | X | X | X | X | X | X |
| USX Corporation[q] | X | X | X | X | X | X | X | X | X | X | X | X |
| Valero Energy Corporation | | | | | | | | | | | | X |
| The Williams Companies, Inc. | | | | | | | | | | | | X |

[a]American Petrofina, Inc. changed its name to Fina, Inc., effective April 17, 1991.

[b]Formerly Standard Oil Company (Indiana).

[c]Amoco merged with British Petroleum plc and became BP Amoco plc on December 31, 1998. BP America was renamed BP Amoco, Inc. The companies reported separately for 1998.

[d]Ashland was dropped from the FRS system for 1998 after spinning off downstream and coal operations and disposing of upstream operations.

[e]In 1987, British Petroleum acquired all shares in Standard Oil Company (Ohio) that it did not already control and renamed its U.S. affiliate, BP America, Inc.

[f]Burlington Resources was added to the FRS system and Burlington Northern was dropped for 1988. Data for Burlington Resources covers the full year 1988 even though that company was not created until May of that year.

[g]Formerly Standard Oil Company of California.

[h]Chevron acquired Gulf Oil in 1984, but separate data for Gulf continued to be available for the full 1984 year.

[i]Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.

[j]DuPont acquired Conoco in 1981. Separate data for Conoco were available for 1981; DuPont was included in the FRS system in 1982.

[k]Dupont was dropped from the FRS system when Conoco was spun-off in 1998. Conoco began reporting separately again in 1998.

[l]Equilon is a joint venture combining Shell's and Texaco's western and midwestern U.S. refining and marketing businesses and nationwide trading transportation and lubricants businesses. Net income is duplicated in the FRS system since Shell and Texaco account for this investment using the equity method.

[m]In December 1998, Exxon and Mobil agreed to merge. Both companies reported separately for 1998.

[n]Texaco acquired Getty in 1984; however, Getty was treated as a separate FRS company for that year.

[o]In 1998, Kerr-McGee and Oryx merged. The financial reporting for both was consolidated under Kerr-McGee for 1998.

[p]LYONDELL-CITGO is a limited partnership owned by Lyondell Chemical Company and Citgo. There will be some duplication of net income since Citgo accounts for its investment using the equity method.

[q]U.S. Steel (now USX) acquired Marathon in 1982.

[r]Mobil acquired Superior in 1984, but both companies were treated separately for that year.

[s]Motiva is a joint venture approximately equally owned by Shell, Texaco and Saudi Refining, Inc. The joint venture combines the company's Gulf and east coast refining and marketing businesses. Duplication exists for the net income related to Shell and Texaco's interests which are accounted for under the equity method.

[t]RTZ America acquired the common stock of Nerco, Inc., on Feb. 17, 1994. In Sept. 1993, Nerco, Inc. sold Nerco Oil & Gas, Inc., its subsidiary. Nerco's 1993 submission includes operations of Nerco Oil & Gas, Inc., through Sept. 28, 1993.

[u]Sun Company spun off Sun Exploration and Development Company (later renamed Oryx Energy Company) during 1988. Both companies were included in the FRS system for 1988; therefore, some degree of duplication exists for that year.

[v]Sun company withdrew from oil and gas exploration and production in 1996. Sun’s 1996 submission includes oil and gas exploration and production activities through September 30, 1996. Refining/marketing activities are included for the entire 1996 calendar year.

[w]Tenneco sold its worldwide oil and gas assets and its refining and marketing assets in 1988. Other FRS companies purchased approximately 70 percent of Tenneco's assets.

[x]Effective June 1, 1991, Total's exploration, production, and marketing operations in Canada were spun off to Total Oil & Gas, a new public entity.

[y]Effective October 15, 1996, Union Pacific Corporation distributed its ownership in the Union Pacific Resources Group, Inc. to its shareholders. Prior to 1996, the FRS system included Union Pacific Corporation. The FRS system includes only Union Pacific Resources Group, Inc. for 1996.
"X" indicates that the company was included in the FRS system for the year indicated.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System".

**Table A2. Example of Nontraceables and Eliminations**

| Financial Items | Consolidated | Elimination | Nontraceable | Refining/ Marketing | Production |
|---|---|---|---|---|---|
| Revenues . . . . . . . . . . . . . . . . | 160 | (80) | - | 160 | 80 |
| Less Expenses: | | | | | |
| General and Administrative . . | 10 | - | 2 | 5 | 3 |
| Other Operations . . . . . . . . . . | 10 | - | - | 5 | 5 |
| Crude . . . . . . . . . . . . . . . . . . . | - | (80) | - | 80 | - |
| Operating Income. . . . . . . . . . | 140 | - | (2) | 70 | 72 |
| Less Interest Expense . . . . . . | 20 | - | 20 | - | - |
| Less Income Taxes . . . . . . . . | 60 | - | (11) | 35 | 36 |
| Net Income . . . . . . . . . . . . . . . | 60 | - | (11) | 35 | 36 |

Note: Numbers in parentheses are negative.

**Table A3. A Comparison Between Full Cost and Successful Efforts Accounting Methods**

| Years | Full Cost | Successful Efforts |
|---|---|---|
| 1973 | | |
| Net Income (dollars) | 1,292,400 | 1,243,300 |
| Net PP&E (dollars) | 8,476,700 | 7,511,300 |
| Net Income/PP&E (percent) | 15.25 | 16.70 |
| 1974 | | |
| Net Income (dollars) | 1,586,400 | 1,544,700 |
| Net PP&E (dollars) | 9,593,300 | 8,563,500 |
| Net Income/PP&E (percent) | 16.54 | 17.98 |

Source: Texaco, Inc., 1974 and 1977 ***Annual Report*** and ***Statistical Supplements***.

## Table A4. The Impact of FASB-52, Foreign Currency Translations, on Stockholders' Equity and Pretax Income, 1982-1998

| Year | Cumulative Translation Gains/Losses | Stockholders' Equity | Percent of Stockholders' Equity | Transaction Gains/Losses | Pretax Income | Percent of Pretax Income |
|---|---|---|---|---|---|---|
| | (million dollars) | | | (million dollars) | | |
| 1982 | -1,764 | 183,933 | -1.0 | -111 | 45,157 | -0.2 |
| 1983 | -1,253 | 192,509 | -0.7 | 35 | 47,420 | 0.1 |
| 1984 | -1,683 | 176,461 | -1.0 | -44 | 47,609 | -0.1 |
| 1985 | 399 | 165,457 | 0.2 | 176 | 43,573 | 0.4 |
| 1986 | 1,786 | 164,601 | 1.1 | 543 | 20,564 | 2.6 |
| 1987 | 3,425 | 165,458 | 2.1 | 176 | 25,006 | 0.7 |
| 1988 | -495 | 164,832 | -0.3 | 89 | 34,285 | 0.3 |
| 1989 | -465 | 160,638 | -0.3 | 142 | 32,281 | 0.4 |
| 1990 | 1,918 | 167,060 | 1.1 | 135 | 37,489 | 0.4 |
| 1991 | 101 | 167,574 | 0.1 | -25 | 25,120 | -0.1 |
| 1992 | -3,341 | 157,295 | -2.1 | 375 | 22,542 | 1.7 |
| 1993 | -637 | 161,769 | -0.4 | 170 | 24,777 | 0.7 |
| 1994 | 1,912 | 165,689 | 1.2 | 280 | 29,592 | 1.0 |
| 1995 | 701 | 166,689 | 0.4 | -48 | 34,233 | -0.1 |
| 1996 | -368 | 177,755 | -0.2 | -22 | 52,808 | -0.1 |
| 1997 | -3,947 | 188,671 | -2.1 | -258 | 51,453 | -0.5 |
| 1998 | 27 | 194,429 | 0.0 | -84 | 16,017 | -0.5 |

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

Energy Finance

# Appendix B Tables

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This is the second year of the new version of the tables. The prior set of Appendix B tables consisted of 52 tables that were published annually for 10 years. (See the crosswalk between the old and new Appendix B tables for a cross reference between the old and new tables numbers, and modifications, if any, that were made.)

The reader should note that a small number of prior year data values changed from last year's report as the result of corrections made by some companies during EIA's audit of the current year's survey submissions. Typically, these differences are immaterial at the company level, and often do not show up in the aggregate.

The reader should also note that due to the large number of new survey respondents included to increase the coverage of the U.S. petroleum refining industry, there are significant changes in some data values between 1997 and 1998, particularly in the petroleum refining tables. These time series anomalies are addressed in the text of the Performance Profiles report.

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File last modified: November 2, 1999

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## Crosswalk between New B Tables and Old B Tables

| New Table | Old Table(s) | Modifications |
|---|---|---|
| B1 | B2 | Unchanged. |
| B2 | B3 | Interest expense added, % change dropped. |
| B3 | B8 | w/ selected financial ratios from old B16 added. |
| B4 | B9 | Unchanged. |
| B5 | B4 | Unchanged. |
| B6 | B5 | Unchanged. |
| B7 | B11 | Line-of-business order changed. |
| B8 | B7 & B6 | Unchanged. |
| B9 | B52 | Unchanged. |
| B10 | B12,13,14 | Net investment in place only. |
| B11 | B15 | Unchanged. |
| B12 | B19 | Unchanged. |
| B13 | B20 | Organized as time series table |
| B14 | B21 | Reorganized as time series |
| B15 | B22 | Unchanged, except that production costs have been incorporated into B16 |
| B16 | B34 | W/ US onshore, offshore & total, & worldwide total included. |
| B17 | B38 | W/ US onshore, offshore & total included (from old B22). |
| B18 | B28 | Acreage data w/ total foreign acreage included. |
| B19 | B23 & 26 | W/ total US industry well completions presented as a time series. |
| B20 | B27 | W/ producing wells from old B28. |

| | | |
|---|---|---|
| B21 | B36 | Unchanged. |
| B22 | B25 | Unchanged. |
| B23 | B30 & 32 | Redesigned to show reserve additions, net purchases of reserves, & production<br><br>For FRS vs. US Industry & includes FRS foreign regions. |
| B24 | B31 & 37 | Unchanged. |
| B25 | B33 & 32 | W/ natural gas production & reserves, & US onshore, offshore, & total included. |
| B26 | B43 | "US Purchases from Unconsolidated Affiliates" is to be included w/ "Purchases from Other US segments." |
| B27 | B42 | Unchanged. |
| B28 | B47 | Unchanged. |
| B29 | B45 & 46 | Unchanged. |
| B30 | B39 | Unchanged. |
| B31 | B40 | Unchanged. |
| B32 | B48 | "Percent of Product Revenues" deleted. |
| B33 | B41 | Units are millions instead of billions. |
| B34 | B49, 50, 51 | Unchanged. |

## Table B1.
## Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1992-1998

| Operating Statistics | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Petroleum and Natural Gas** | | | | | | | |
| Net Production | | | | | | | |
| Crude Oil and Natural Gas Liquids (million barrels) | | | | | | | |
| FRS Companies | 1,750.2 | 1,632.5 | 1,593.8 | 1,570.6 | 1,532.4 | 1,458.8 | 1,388.8 |
| U.S. Industry[1] | 3,219.0 | 3,127.0 | 3,059.0 | 3,004.0 | 3,023.0 | 3,002.0 | 2,824.0 |
| FRS as a Percent of U.S. Industry | 54.4 | 52.2 | 52.1 | 52.3 | 50.7 | 48.6 | 49.2 |
| Natural Gas (billion cubic feet) | | | | | | | |
| FRS Companies | 7,877.7 | 7,651.1 | 7,998.4 | 8,055.3 | 8,191.6 | 8,299.1 | 8,395.9 |
| U.S. Industry[1] | 17,423.0 | 17,789.0 | 18,322.0 | 17,966.0 | 18,861.0 | 19,211.0 | 18,720.0 |
| FRS as a Percent of U.S. Industry | 45.2 | 43.0 | 43.7 | 44.8 | 43.4 | 43.2 | 44.8 |
| Net Imports | | | | | | | |
| Crude Oil and Natural Gas Liquids (million barrels) | | | | | | | |
| FRS Companies | 868.8 | 757.5 | 754.1 | 612.1 | 565.7 | 571.1 | 634.7 |
| U.S. Industry[1] | 2,383.0 | 2,640.9 | 2,788.7 | 2,810.0 | 2,946.6 | 3,191.0 | 3,358.5 |
| FRS as a Percent of U.S. Industry | 36.5 | 28.7 | 27.0 | 21.8 | 19.2 | 17.9 | 18.9 |
| Refinery Capacity (thousand barrels per day) | | | | | | | |
| FRS Companies | 10,952.0 | 10,714.0 | 10,642.0 | 10,427.0 | 10,477.0 | 9,410.0 | 14,277.0 |
| U.S. Industry[1] | 15,804.4 | 15,718.0 | 16,069.3 | 15,981.0 | 16,031.8 | 16,128.7 | 16,567.0 |
| FRS as a Percent of U.S. Industry | 69.3 | 68.2 | 66.2 | 65.2 | 65.4 | 58.3 | 86.2 |
| Refinery Output[2] (thousand barrels per day) | | | | | | | |
| FRS Companies | 10,994.0 | 10,822.0 | 10,812.0 | 10,652.0 | 10,954.0 | 10,030.0 | 14,929.0 |
| U.S. Industry[1] | 15,932.0 | 16,341.2 | 16,341.1 | 16,534.7 | 16,800.7 | 17,234.3 | 17,499.6 |
| FRS as a Percent of U.S. Industry | 69.0 | 66.2 | 66.2 | 64.4 | 65.2 | 58.2 | 85.3 |
| **Bituminous Coal and Lignite Production** (million tons) | | | | | | | |
| FRS Companies | 251.9 | 197.3 | 179.7 | 165.4 | 169.4 | 163.3 | 73.9 |
| U.S. Industry[1] | 994.1 | 941.1 | 1,028.9 | 1,028.3 | 1,059.1 | 1,085.3 | 1,112.9 |
| FRS as a Percent of U.S. Industry | 25.3 | 21.0 | 17.5 | 16.1 | 16.0 | 15.0 | 6.6 |

[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 1998 Annual Report November 1999). 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 3,063 million barrels in 1998 and 3,143 million barrels in 1997. (See Energy Information Administration, Petroleum Supply Annual 1998, Volume I (June 1999), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 18,862 billion cubic feet in 1998 and 18,902 billion cubic feet in 1997. (See Energy Information Administration, Natural Gas Monthly, September 1999, p. 8.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1998 Annual Report (November 1999). 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, 1997 and 1998. Coal production: Energy Information Administration, Form EIA-7A (Coal Production Report); see Coal Industry Annual 1998 (November 1999).

*Last Updated on 12/17/99*

**Table B2.**
**Selected Financial Items for the FRS Companies and the S&P Industrials, 1997-1998**
(Billion Dollars)

| Selected Financial Items | FRS Companies | | S&P Industrials | |
|---|---|---|---|---|
| | 1997 | 1998 | 1997 | 1998 |
| **Income Statement** | | | | |
| Operating Revenues | 525.1 | 484.2 | 3,787.0 | 3,923.5 |
| Operating Expenses | -478.4 | -468.3 | -3,352.1 | -3,502.6 |
| Operating Income | 46.7 | 15.8 | 434.9 | 420.9 |
| Interest Expense | -6.4 | -7.3 | 77.1 | 80.6 |
| Other Income[1] | 4.1 | 1.4 | -78.7 | -45.1 |
| Income Taxes | -18.6 | -4.7 | -129.8 | -120.6 |
| Net Income | 32.1 | 12.5 | 226.4 | 255.1 |
| **Cash Flows from Operations[2]** | | | | |
| Net Income | 32.1 | 12.5 | 226.4 | 255.1 |
| Other Items, Net[3] | 33.2 | 35.6 | 233.6 | 196.7 |
| Net Cash Flow from Operations | 65.3 | 48.2 | 460.0 | 451.8 |
| **Cash Flows from Investing Activities[2]** | | | | |
| Additions to PP&E | -54.2 | -69.9 | -303.3 | -311.7 |
| Other Investment Activities, Net[4] | 8.2 | 15.3 | -56.2 | -115.4 |
| Net Cash Flow from Investing Activities | -46.0 | -54.7 | -359.5 | -427.1 |
| **Cash Flows from Financing Activities[2]** | | | | |
| Proceeds from Long-Term Debt | 17.9 | 27.1 | 263.5 | 372.4 |
| Proceeds from Equity Security Offerings | 1.5 | 9.1 | 29.3 | 43.1 |
| Dividends to Shareholders | -16.9 | -17.2 | -84.7 | -90.8 |
| Reductions in Long-Term Debt | -19.8 | -18.0 | -214.3 | -254.1 |
| Stock Repurchases | -7.9 | -5.8 | -94.9 | -120.7 |
| Other Financing Activities, Net | 5.5 | 6.9 | 9.6 | 24.9 |
| Net Cash Flow from Financing Activities | -19.7 | 2.1 | -91.6 | -25.3 |
| **Effect of Exchange Rate Changes on Cash** | -0.3 | 0.0 | -2.9 | 0.4 |
| **Increase (Decrease) in Cash and Cash Equivalents** | -0.6 | -4.4 | 5.5 | -0.2 |

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

*Last Updated on 12/20/99*

**Table B3.**
**Balance Sheet Items and Financial Ratios for FRS Companies and S&P Industrials, 1997-1998**

| | FRS Companies | | S&P Industrials | |
|---|---|---|---|---|
| | **1997** | **1998** | **1997** | **1998** |
| **Balance Sheet** | (billion dollars) | | | |
| Assets | | | | |
| Current Assets | 100.9 | 94.2 | 1,043.4 | 1,148.1 |
| Noncurrent Assets | | | | |
| Property, Plant, and Equipment | | | | |
| Gross | 636.9 | 671.0 | 2,638.7 | 2,732.9 |
| Accumulated DD&A | -333.3 | -334.5 | -1,240.0 | -1,272.8 |
| Net | 303.6 | 336.5 | 1,398.7 | 1,460.1 |
| Investments and Advances | 44.2 | 53.9 | 110.4 | 130.3 |
| Other Noncurrent Assets | 35.2 | 35.8 | 1,549.3 | 1,813.6 |
| Subtotal Noncurrent Assets | 382.9 | 426.3 | 1,951.0 | 2,269.2 |
| Total Assets | 483.8 | 520.4 | 4,101.9 | 4,552.1 |
| Liabilities and Stockholders Equity | | | | |
| Liabilities | | | | |
| Current Liabilities | 106.9 | 113.9 | 944.4 | 1,059.7 |
| Long-Term Debt | 73.4 | 94.6 | 829.3 | 927.5 |
| Other Long-Term Items | 106.6 | 107.1 | 978.2 | 1,103.6 |
| Minority Interest | 8.2 | 10.4 | 41.7 | 50.0 |
| Subtotal Liabilities and Other Items | 295.1 | 326.0 | 2,793.6 | 3,140.8 |
| Stockholders' Equity | | | | |
| Retained Earnings | 160.8 | 165.8 | 964.4 | 1,008.0 |
| Other Equity | 27.9 | 28.7 | 343.9 | 403.2 |
| Subtotal Stockholders' Equity | 188.7 | 194.4 | 1,308.3 | 1,411.3 |
| Total Liabilities and Stockholders' Equity | 483.8 | 520.4 | 4,101.9 | 4,552.1 |
| **Financial Ratios** | (percent) | | | |
| Net Income/Stockholders' Equity | 17.0 | 6.4 | 17.3 | 18.1 |
| Net Income plus Interest/Total Invested Capital | 14.7 | 6.9 | 14.2 | 14.4 |
| Dividends/Net Cash Flow from Operations | 25.9 | 35.6 | 18.4 | 20.1 |
| Long-term Debt/Stockholders' Equity | 38.9 | 48.7 | 63.4 | 65.7 |

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

*Last Updated on 12/20/99*

**Table B4.**
**Consolidated Balance Sheet for FRS Companies , 1992-1998**
(Billion Dollars)

| Balance Sheet Items | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | | | | |
| Current Assets | | | | | | | |
| Cash & Marketable Securities | 12.1 | 14.1 | 13.2 | 12.2 | 13.4 | 12.2 | 8.1 |
| Trade Accounts & Notes Receivable | 44.6 | 41.7 | 45.8 | 48.8 | 56.2 | 51.2 | 47.8 |
| Inventories | | | | | | | |
| Raw Materials & Products | 26.2 | 23.7 | 22.9 | 22.6 | 22.7 | 21.4 | 21.6 |
| Materials & Supplies | 4.6 | 4.3 | 4.4 | 4.1 | 3.8 | 3.7 | 3.8 |
| Other Current Assets | 10.4 | 9.6 | 10.2 | 10.9 | 12.1 | 12.4 | 12.9 |
| Total Current Assets | 97.9 | 93.5 | 96.6 | 98.6 | 108.2 | 100.9 | 94.2 |
| Non-current Assets | | | | | | | |
| Property, Plant & Equipment | | | | | | | |
| Gross | 599.9 | 607.9 | 624.1 | 640.2 | 635.0 | 636.9 | 671.0 |
| Accumulated DD&A | 290.2 | 300.0 | 315.4 | 329.8 | 331.6 | 333.3 | 334.5 |
| Net | 309.7 | 307.9 | 308.7 | 310.5 | 303.4 | 303.6 | 336.5 |
| Investments & Advances to Unconsolidated Affiliates | 21.9 | 23.6 | 25.9 | 29.0 | 32.3 | 44.2 | 53.9 |
| Other Non-current Assets | 24.2 | 26.3 | 26.2 | 26.5 | 26.8 | 35.2 | 35.8 |
| Total Non-current Assets | 355.7 | 357.8 | 360.8 | 366.0 | 362.4 | 382.9 | 426.3 |
| **Total Assets** | 453.6 | 451.3 | 457.4 | 464.6 | 470.6 | 483.8 | 520.4 |
| **Liabilities & Stockholders' Equity** | | | | | | | |
| Liabilities | | | | | | | |
| Current Liabilities | | | | | | | |
| Trade Accounts & Notes Payable | 53.1 | 49.1 | 51.5 | 53.1 | 61.4 | 57.7 | 62.8 |
| Other Current Liabilities | 48.7 | 47.0 | 45.8 | 50.8 | 48.8 | 49.2 | 51.1 |
| Long-Term Debt | 93.5 | 89.4 | 88.1 | 84.6 | 70.9 | 73.4 | 94.6 |
| Deferred Income Tax Credits | 44.7 | 45.5 | 45.0 | 45.5 | 45.5 | 46.3 | 49.0 |
| Other Deferred Credits | 16.5 | 15.9 | 16.8 | 17.3 | 19.2 | 18.8 | 18.4 |
| Other Long-Term Items | 34.9 | 37.7 | 39.3 | 40.7 | 40.6 | 41.6 | 39.7 |
| Minority Interest in Consolidated Affiliates | 4.8 | 5.0 | 5.1 | 5.8 | 6.6 | 8.2 | 10.4 |
| Total Liabilities | 296.3 | 289.6 | 291.7 | 297.9 | 292.9 | 295.1 | 326.0 |
| Stockholders' Equity | 139.2 | 142.0 | 145.0 | 151.4 | 156.3 | 160.8 | 165.8 |
| Retained Earnings | 18.1 | 19.8 | 20.7 | 15.3 | 21.4 | 27.9 | 28.7 |
| Other Equity | | | | | | | |
| Total Stockholders' Equity | 157.3 | 161.8 | 165.7 | 166.7 | 177.8 | 188.7 | 194.4 |
| **Total Liabilities & Stockholders' Equity** | 453.6 | 451.3 | 457.4 | 464.6 | 470.6 | 483.8 | 520.4 |
| **Memo:** | | | | | | | |
| Foreign Currency Translation Adjustment | | | | | | | |
| Cumulative at Year End | -6.6 | -7.3 | 0.7 | 1.5 | 1.2 | -2.7 | -2.3 |
| Foreign Currency Translation Adjustment | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| for the Current Year | -3.3 | -0.6 | 1.9 | 0.7 | -0.4 | -3.9 | 0.0 |
| Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). | | | | | | | |

*Last Updated on 12/20/99*

# Table B5.
## Consolidating Statement of Income for FRS Companies, 1998
(Million Dollars)

| Income Statement Items | Consolidated | Eliminations & Nontraceables | Petroleum | Coal | Other Energy | Non-energy |
|---|---|---|---|---|---|---|
| **Operating Revenues** | 484,154 | -9,113 | 426,874 | 1,736 | 17,540 | 47,117 |
| **Operating Expenses** | | | | | | |
| General Operating Expenses | 418,893 | -8,392 | 370,831 | 1,268 | 16,158 | 39,028 |
| DD&A | 35,445 | 486 | 31,675 | 137 | 326 | 2,821 |
| General & Administrative | 13,968 | 2,485 | 8,319 | 51 | 589 | 2,524 |
| Total Operating Expenses | 468,306 | -5,421 | 410,825 | 1,456 | 17,073 | 44,373 |
| **Operating Income** | 15,848 | -3,692 | 16,049 | 280 | 467 | 2,744 |
| **Other Revenue & (Expense)** | | | | | | |
| Earnings of Unconsolidated Affiliates | 1,299 | -148 | 833 | W | W | 51 |
| Other Dividend & Interest Income | 2,688 | 2,688 | - | - | - | - |
| Gain/Loss on Disposition of PP&E | 2,656 | 264 | 2,443 | W | W | -53 |
| Interest Expenses & Financial Charges | -7,285 | -7,285 | - | - | - | - |
| Minority Interest in Income | -764 | -764 | - | - | - | - |
| Foreign Currency Translation Effects | -84 | -84 | - | - | - | - |
| Other Revenue & (Expense) | 1,659 | 1,659 | - | - | - | - |
| **Total Other Revenue & (Expense)** | 169 | -3,670 | 3,276 | 22 | 543 | -2 |
| **Pretax Income** | 16,017 | -7,362 | 19,325 | 302 | 1,010 | 2,742 |
| **Income Tax Expense** | 4,709 | -2,883 | 6,544 | 78 | 66 | 904 |
| **Discontinued Operations** | 1,353 | W | W | W | 0 | W |
| **Extraordinary Items and Cumulative Effect of Accounting Changes** | -142 | W | W | W | 0 | W |
| **Net Income** | 12,519 | -3,565 | 12,809 | 500 | 944 | 1,831 |

- = Not available.

W = Data withheld to avoid disclosure.

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

*Last Updated on 12/20/99*

## Table B6.
## Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1998
(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 | 94,812 | 43,337 | 68,144 | 7,048 | 51,858 | 35,451 | 33,119 | 0 |
| Refined Products Sales | 148,173 | 79 | 147,456 | 1,385 | 114,238 | W | 121,344 | 0 |
| Transportation Revenues | 12,912 | 832 | 6,742 | 6,852 | 2,594 | 371 | 659 | 2,375 |
| Management and Processing Fees | 1,053 | 392 | 765 | W | 1,491 | 261 | 1,238 | W |
| Other | 11,723 | 1,700 | 9,566 | W | 4,861 | W | 4,078 | W |
| Total Operating Revenues | 268,673 | 46,340 | 232,673 | 16,110 | 175,042 | 37,293 | 160,438 | 2,402 |
| **Operating Expenses** | | | | | | | | |
| General Operating Expenses | 233,835 | 31,845 | 216,789 | 11,472 | 153,661 | 23,422 | 152,827 | 2,142 |
| DD&A | 19,373 | 12,796 | 4,700 | 1,877 | 12,302 | 10,439 | 1,776 | 87 |
| General & Administrative | 6,383 | 1,063 | 4,435 | 1,064 | 2,112 | 814 | 1,603 | 54 |
| Total Operating Expenses | 259,591 | 45,704 | 225,924 | 14,413 | 168,075 | 34,675 | 156,206 | 2,283 |
| **Operating Income** | 9,082 | 636 | 6,749 | 1,697 | 6,967 | 2,618 | 4,232 | 119 |
| **Other Revenue & (Expense)** | | | | | | | | |
| Earnings of Unconsolidated Affiliates | -659 | -1,982 | 869 | 454 | 1,492 | 1,371 | 115 | 6 |
| Gain(Loss) on Disposition of PP&E | 1,888 | 1,554 | 375 | -41 | 555 | 486 | 68 | -1 |
| Total Other Revenue & (Expense) | 1,229 | -428 | 1,244 | 413 | 2,047 | 1,857 | 183 | 5 |
| **Pretax Income** | 10,311 | 208 | 7,993 | 2,110 | 9,014 | 4,475 | 4,415 | 124 |
| **Income Tax Expense** | 2,623 | -277 | 2,142 | 758 | 3,921 | 2,445 | 1,445 | 31 |
| **Discontinued Operations** | W | 0 | W | 0 | W | 0 | W | 0 |
| **Extraordinary Items and Cumulative Effect of Accounting Changes** | W | 0 | W | 0 | W | 0 | W | 0 |
| **Contribution To Net Income** | 7,741 | 485 | 5,904 | 1,352 | 5,068 | 2,030 | 2,945 | 93 |
| W = Data withheld to avoid disclosure. | | | | | | | | |
| Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). | | | | | | | | |

*Last Updated on 12/20/99*

**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, 1998**
(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 | 94,924 | 4,422 | 22,633 | -336 | 12,796 |
| Refining/Marketing | | | | | |
| Refining | 38,434 | 9,190 | 4,370 | 67 | 2,777 |
| Marketing | 19,712 | 1,679 | 2,446 | 206 | 1,507 |
| Refining/Marketing Transport | | | | | |
| Pipelines | 2,743 | 868 | 346 | 170 | 161 |
| Marine | 970 | W | 160 | W | 75 |
| Other | 1,304 | W | 293 | W | 180 |
| Total U.S. Refining/Marketing | 63,163 | 11,908 | 7,615 | 612 | 4,700 |
| Rate Regulated Pipelines | | | | | |
| Refined Products | 1,203 | 250 | 137 | W | 55 |
| Natural Gas | 20,209 | 2,114 | 4,592 | 339 | 1,484 |
| Crude Oil and Liquids | 5,893 | 872 | 215 | W | 338 |
| Total Rate Regulated Pipelines | 27,305 | 3,236 | 4,944 | 446 | 1,877 |
| Total U.S. Petroleum | 185,392 | 19,566 | 35,192 | 722 | 19,373 |
| Foreign | | | | | |
| Production | 80,388 | 10,011 | 24,429 | 1,630 | 10,439 |
| Refining/Marketing | 24,857 | 11,023 | 2,645 | W | 1,776 |
| International Marine | 959 | 86 | 17 | W | 87 |
| Total Foreign Petroleum | 106,204 | 21,120 | 27,091 | 2,526 | 12,302 |
| Total Petroleum | 291,596 | 40,686 | 62,283 | 3,248 | 31,675 |
| **Coal** | | | | | |
| Foreign | W | W | W | W | W |
| United States | W | W | W | W | W |
| Total Coal | 1,768 | 175 | 197 | 13 | 137 |
| **Other Energy** | | | | | |
| Foreign | 1,297 | 2,558 | 264 | 830 | 91 |
| United States | 2,836 | 485 | 275 | 175 | 235 |
| Total Other Energy | 4,133 | 3,043 | 539 | 1,005 | 326 |
| **Nonenergy** | | | | | |
| Foreign Chemicals | 6,074 | 3,232 | 1,613 | 405 | 430 |
| U.S. Chemicals | 19,321 | 2,948 | 2,923 | 281 | 1,749 |
| Foreign Other Nonenergy | 1,170 | 529 | W | W | W |
| U.S. Other Nonenergy | 5,216 | 2,019 | W | W | W |
| Total Nonenergy | 31,781 | 8,728 | 5,810 | 2,030 | 2,821 |
| **Nontraceable** | 7,268 | 1,242 | 1,085 | -1,073 | 486 |
| **Consolidated** | 336,546 | 53,874 | 69,914 | 5,223 | 35,445 |

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

*Last Updated on 12/20/99*

**Table B8.**
**Return on Investment for Lines of Business for FRS Companies Ranked by Total Energy Assets, 1997-1998**
(Percent)

| Line of Business | All FRS | | Top Four | | Five through Twelve | | All Other | |
|---|---|---|---|---|---|---|---|---|
| | 1997 | 1998 | 1997 | 1998 | 1997 | 1998 | 1997 | 1998 |
| | | | | | | | | |
| **Petroleum** | 10.8 | 3.9 | 13.1 | 7.2 | 9.0 | 1.8 | 8.3 | 1.7 |
| U.S. Petroleum | 10.0 | 3.8 | 12.3 | 6.5 | 9.5 | 2.7 | 8.0 | 3.1 |
| Oil and Gas Production | 12.5 | 0.5 | 14.8 | 3.9 | 11.9 | -1.4 | 10.6 | -0.3 |
| Refining/Marketing | 6.6 | 7.9 | 7.5 | 9.9 | 8.6 | 13.7 | 0.2 | 3.6 |
| Pipelines | 6.7 | 4.4 | 19.8 | 12.6 | 1.6 | -0.2 | 10.2 | 7.8 |
| Foreign Petroleum | 11.9 | 4.0 | 13.7 | 7.6 | 7.7 | -0.4 | 9.6 | -4.8 |
| Oil and Gas Production | 12.5 | 2.2 | 15.2 | 7.0 | 8.5 | -1.4 | 9.8 | -5.7 |
| Refining/Marketing | 10.5 | 8.2 | 11.6 | 8.4 | 2.6 | 7.5 | 5.7 | 5.9 |
| International Marine | 11.8 | 8.9 | 12.0 | 11.1 | W | W | W | W |
| **Coal** | 7.2 | 25.7 | 3.1 | 8.7 | 7.9 | W | 9.6 | 69.0 |
| **Other Energy** | 7.0 | 13.2 | 8.9 | 18.6 | 6.0 | 11.0 | 6.3 | 8.2 |
| **Nonenergy** | 10.9 | 4.5 | 12.5 | 4.4 | 9.5 | 5.3 | 15.4 | 2.7 |

W = Data withheld to avoid disclosure.

Note: Return on investment measured as contribution to net income/net investment in place.

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

*Last Updated on 12/20/99*

**Table B9.**
**Research and Development Expenditures for FRS Companies, 1992-1998**
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| **Sources of R&D Funds** | | | | | | | |
| Federal Government | 22 | 16 | 15 | W | W | W | W |
| Internal Company | 3,603 | 3,308 | 2,985 | 2,817 | 2,675 | 2,841 | 1,668 |
| Other Sources | 60 | 26 | 50 | W | W | W | W |
| Total Sources | 3,685 | 3,350 | 3,050 | 2,861 | 2,717 | 2,885 | 1,707 |
| **Breakdown of R&D Expenditures** | | | | | | | |
| Oil & Gas Recovery | 781 | 671 | 572 | 494 | 482 | 585 | 606 |
| Other Petroleum | 652 | 569 | 531 | 461 | 432 | 380 | 365 |
| Coal Gasification/Liquefaction | W | W | W | W | W | W | W |
| Other Coal | W | W | W | W | W | W | W |
| Nuclear and Other Energy | 80 | 121 | 116 | 50 | 51 | 54 | 40 |
| Nonenergy | 2,041 | 1,902 | 1,741 | 1,744 | 1,617 | 1,738 | 572 |
| Unassigned | 117 | 77 | 71 | 100 | 127 | 120 | 117 |
| Total Expenditures | 3,685 | 3,350 | 3,050 | 2,861 | 2,717 | 2,885 | 1,707 |

W = Data withheld to avoid disclosure.

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

*Last Updated on 12/20/99*

**Table B10.**
**Size Distribution of Net Investment in Place for FRS Companies Ranked by Total Energy Assets, 1998**
(Percent)

| Line of Business | Top Four | Five through Twelve | All Other | All FRS |
|---|---|---|---|---|
| | | | | |
| **Petroleum** | 38.9 | 33.5 | 27.6 | 100.0 |
| United States | 24.8 | 38.4 | 36.8 | 100.0 |
| Production | 30.2 | 44.9 | 24.9 | 100.0 |
| Refining/Marketing | 25.0 | 26.7 | 48.4 | 100.0 |
| Refining | 22.4 | 27.3 | 50.3 | 100.0 |
| Marketing | 33.3 | 25.0 | 41.7 | 100.0 |
| Rate Regulated Pipelines | 6.9 | 46.0 | 47.1 | 100.0 |
| Foreign | 61.4 | 25.7 | 12.8 | 100.0 |
| Production | 51.6 | 31.8 | 16.7 | 100.0 |
| Refining/Marketing | 85.2 | 11.3 | 3.5 | 100.0 |
| International Marine | 99.2 | 0.7 | 0.1 | 100.0 |
| **Coal** | 65.6 | 4.7 | 29.7 | 100.0 |
| **Other Energy** | 32.6 | 55.2 | 12.2 | 100.0 |
| **Nonenergy** | 38.9 | 45.1 | 16.0 | 100.0 |
| Chemicals | 44.4 | 41.8 | 13.7 | 100.0 |
| Other Nonenergy | 19.2 | 56.9 | 23.9 | 100.0 |
| **Consolidated** | 39.4 | 34.8 | 25.8 | 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).

*Last Updated on 12/20/99*

**Table B11.**
**Consolidated Statement of Cash Flows for FRS Companies, 1992-1998**
(Million Dollars)

| Cash Flows [1] | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Cash Flows From Operations** | | | | | | | |
| Net Income | 1,757 | 15,488 | 16,547 | 21,131 | 32,029 | 32,082 | 12,519 |
| Minority Interest in Income | 344 | 397 | 513 | 731 | 845 | 896 | 764 |
| Noncash Items: | | | | | | | |
| DD&A | 31,033 | 30,355 | 30,667 | 36,698 | 29,331 | 29,569 | 35,445 |
| Dry Hole Expense, This Year | 1,986 | 1,673 | 1,805 | 1,510 | 1,812 | 2,069 | 2,518 |
| Deferred Income Taxes | -3,929 | -990 | 509 | -327 | 2,863 | 2,301 | -1,123 |
| Recognized Undistributed (Earnings)/Losses | | | | | | | |
| of Unconsolidated Affiliates | -350 | -137 | -372 | -845 | -226 | -374 | 2,987 |
| (Gain)/Loss on Disposition of PP&E | -1,294 | -941 | -570 | -2,445 | -1,940 | -2,716 | -2,656 |
| Changes in Operating Assets and Liabilities | | | | | | | |
| and Other Noncash Items | 3,284 | 2,646 | -1,884 | -763 | -365 | 298 | -3,792 |
| Other Cash Items, Net | 11,927 | 1,705 | 1,084 | 2,808 | -165 | 1,197 | 1,500 |
| Net Cash Flow From Operations | 44,758 | 50,196 | 48,299 | 58,498 | 64,184 | 65,322 | 48,162 |
| **Cash Flows From Investing Activities** | | | | | | | |
| Additions to PP&E: | | | | | | | |
| Due to Mergers and Acquisitions | -874 | -306 | -2,271 | -4,137 | -2,281 | -5,579 | -18,868 |
| Other | -39,604 | -37,755 | -35,217 | -40,356 | -41,872 | -48,666 | -51,046 |
| Total Additions to PP&E | -40,478 | -38,061 | -37,488 | -44,493 | -44,153 | -54,245 | -69,914 |
| Additions to Investments and Advances | -1,483 | -2,318 | -1,588 | -3,208 | -5,799 | -7,685 | -5,223 |
| Proceeds From Disposals of PP&E | 7,268 | 11,757 | 6,447 | 9,063 | 10,942 | 9,320 | 16,243 |
| Other Investment Activities, Net | -1,584 | -2,242 | -2,363 | 4,086 | 1,608 | 6,587 | 4,235 |
| Cash Flow From Investing Activities | -36,277 | -30,864 | -34,992 | -34,552 | -37,402 | -46,023 | -54,659 |
| **Cash Flows From Financing Activities** | | | | | | | |
| Proceeds From Long-Term Debt | 24,745 | 18,982 | 12,500 | 19,929 | 10,708 | 17,901 | 27,072 |
| Proceeds From Equity Security Offerings | 3,438 | 2,146 | 2,614 | 3,471 | 1,171 | 1,507 | 9,112 |
| Reductions in Long-Term Debt | -25,284 | -20,886 | -13,760 | -18,657 | -18,883 | -19,774 | -18,019 |
| Purchase of Treasury Stock | -824 | -514 | -1,010 | -10,035 | -1,299 | -7,910 | -5,776 |
| Dividends to Shareholders | -13,521 | -13,563 | -14,906 | -15,238 | -15,585 | -16,941 | -17,169 |
| Other Financing Activities, Including Net Change | | | | | | | |
| in Short-Term Debt | 2,308 | -4,102 | -1,091 | -2,350 | -578 | 5,537 | 6,859 |
| Cash Flow From Financing Activities | -9,138 | -17,937 | -15,653 | -22,880 | -24,466 | -19,680 | 2,079 |
| | | | | | | | |
| **Effect of Exchange Rate on Cash** | -359 | -198 | 131 | 14 | 3 | -255 | -13 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Net Increase/(Decrease) in Cash and Cash Equivalents** | -1,016 | 1,197 | -2,215 | 1,080 | 2,319 | -636 | -4,431 |
| [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). | | | | | | | |

*Last Updated on 12/20/99*

**Table B12.**
**Composition of Income Taxes for FRS Companies, 1992-1998**
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Income Taxes (as per Financial Statements)** | | | | | | | |
| Current Paid or Accrued: | | | | | | | |
| U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax | 2,355 | 2,584 | 1,907 | 4,486 | 6,141 | 5,656 | 603 |
| U.S. Federal Investment Tax Credit | -41 | -76 | 0 | -162 | -146 | -93 | -85 |
| Effect of Alternative Minimum Tax | 450 | -158 | 30 | 151 | -325 | -400 | -16 |
| U.S. State & Local Income Taxes | 759 | 462 | 528 | 649 | 745 | 794 | 443 |
| Foreign Income Taxes | | | | | | | |
| Canada | 558 | 660 | 705 | 634 | 745 | 932 | 456 |
| Europe and Former Soviet Union [1] | 2,066 | 1,947 | 2,300 | 2,752 | 3,862 | 2,927 | 1,666 |
| Africa | 1,509 | 1,256 | 1,127 | 1,204 | 1,956 | 1,926 | 442 |
| Middle East | 1,275 | 893 | 835 | 1,024 | 1,326 | 802 | 564 |
| Other Eastern Hemisphere | 2,180 | 2,075 | 2,085 | 1,882 | 2,195 | 1,901 | 991 |
| Other Western Hemisphere | 420 | 440 | 464 | 514 | 729 | 1,739 | 749 |
| Total Foreign | 8,008 | 7,271 | 7,516 | 8,010 | 10,813 | 10,227 | 4,868 |
| Total Current | 11,531 | 10,083 | 9,981 | 13,134 | 17,228 | 16,184 | 5,813 |
| Deferred | | | | | | | |
| U.S. Federal, before Investment Tax Credit | -1,723 | -549 | 691 | -793 | 1,410 | 1,477 | -373 |
| U.S. Federal Investment Tax Credit | -43 | -32 | 26 | 61 | 69 | -2 | -28 |
| Effect of Alternative Minimum Tax | -564 | 117 | -51 | -158 | 312 | 400 | -16 |
| U.S. State & Local Income Taxes | 20 | -19 | -56 | -30 | 56 | 54 | 104 |
| Foreign | -594 | -456 | 43 | 537 | 930 | 519 | -791 |
| Total Deferred | -2,904 | -939 | 653 | -383 | 2,777 | 2,448 | -1,104 |
| **Total Income Tax Expense** | 8,627 | 9,144 | 10,634 | 12,751 | 20,005 | 18,632 | 4,709 |
| **Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate** | | | | | | | |
| Consolidated Pretax Income/(Loss) | 22,542 | 24,777 | 29,592 | 34,233 | 52,808 | 51,453 | 16,017 |
| Less: Foreign Source Income not Subject to U.S. Tax | 2,753 | 3,233 | 3,575 | 4,038 | 6,230 | 5,827 | 251 |
| Equals: Income Subject to U.S. Tax | 19,789 | 21,544 | 26,017 | 30,195 | 46,578 | 45,626 | 15,766 |
| Less: U.S. State & Local Income Taxes | 748 | 509 | 438 | 440 | 782 | 785 | 570 |
| Less: Applicable Foreign Income Taxes Deducted | 1,121 | 638 | 327 | 377 | 554 | 312 | 32 |
| Equals: Pretax Income Subject to U.S. Tax | 17,920 | 20,397 | 25,252 | 29,378 | 45,242 | 44,529 | 15,164 |
| Tax Provision Based on Previous Line | 6,082 | 7,138 | 8,842 | 10,281 | 15,834 | 15,621 | 5,332 |
| Increase/(Decrease) in Taxes Due To: | | | | | | | |
| Foreign Tax Credits Recognized | -4,596 | -4,754 | -4,831 | -5,661 | -6,926 | -6,982 | -3,563 |
| U.S. Federal Investment Tax Credit Recognized | -83 | -108 | -34 | -97 | -123 | -137 | -124 |
| Statutory Depletion | -66 | -39 | -52 | -70 | -54 | -63 | -30 |
| Effect of Alternative Minimum Tax | -87 | -1 | -14 | 0 | 1 | 0 | -16 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Other | -826 | -352 | -1,314 | -868 | -1,273 | -1,399 | -1,485 |
| **Actual U.S. Federal Tax Provision (Refund)** | 424 | 1,884 | 2,597 | 3,585 | 7,459 | 7,040 | 114 |

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

*Last Updated on 12/20/99*

**Table B13.**
**U.S. Taxes Other Than Income Taxes for FRS Companies, 1992-1998**
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| **Production Taxes** | | | | | | | |
| Oil and Gas Production | 1,967 | 1,906 | 1,719 | 1,693 | 2,098 | 1,965 | 1,176 |
| Coal | 211 | 187 | 126 | 157 | 139 | 172 | 47 |
| Other [1] | 7 | 5 | 5 | 11 | 1 | 1 | 0 |
| Total Production Taxes | 2,185 | 2,098 | 1,850 | 1,861 | 2,238 | 2,138 | 1,223 |
| **Superfund** | 305 | 320 | 291 | 293 | 14 | W | W |
| **Import Duties** | 99 | 127 | 122 | 104 | 260 | W | W |
| **Sales, Use, and Property** | 3,035 | 3,104 | 3,089 | 2,886 | 2,516 | 2,407 | 2,648 |
| **Payroll** | 2,222 | 2,134 | 1,986 | 1,844 | 1,531 | 1,406 | 1,357 |
| **Other Taxes** | 1,307 | 638 | 630 | 566 | 514 | 559 | 360 |
| **Total Taxes Paid (Other Than Income Taxes)** | 9,153 | 8,421 | 7,968 | 7,554 | 7,073 | 6,601 | 5,660 |
| **Excise Taxes Collected** | 23,782 | 25,317 | 30,092 | 30,813 | 32,426 | 30,984 | 39,918 |

[1] Nuclear, Other Energy, and Nonenergy.
W = Data withheld to avoid disclosure.

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

*Last Updated on 12/20/99*

**Table B14.**
**Oil and Gas Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1992-1998**
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **United States** | | | | | | | |
| **Exploration** | | | | | | | |
| Acquisition of Unproved Acreage | 257 | 355 | 477 | 595 | 997 | 2,653 | 3,912 |
| Geological and Geophysical | 475 | 409 | 405 | 486 | 625 | 750 | 916 |
| Drilling and Equipping [1] | 1,185 | 1,370 | 1,887 | 1,833 | 2,338 | 2,905 | 2,964 |
| Other | 758 | 652 | 619 | 596 | 693 | 690 | 954 |
| Total Exploration | 2,675 | 2,786 | 3,388 | 3,510 | 4,653 | 6,998 | 8,746 |
| **Development** | | | | | | | |
| Acquisition of Proved Acreage | 541 | 599 | 1,576 | 980 | 922 | 2,928 | 3,568 |
| Lease Equipment | 1,450 | 1,640 | 1,386 | 1,425 | 1,613 | 1,823 | 2,688 |
| Drilling and Equipping [1] | 3,487 | 4,012 | 4,524 | 5,433 | 6,154 | 8,540 | 7,769 |
| Other | 2,161 | 1,895 | 1,714 | 1,086 | 1,290 | 1,557 | 1,657 |
| Total Development | 7,639 | 8,146 | 9,200 | 8,924 | 9,979 | 14,848 | 15,682 |
| **Total U.S. Exploration and Development** | 10,314 | 10,932 | 12,588 | 12,434 | 14,632 | 21,846 | 24,428 |
| **Foreign** | | | | | | | |
| **Exploration** | | | | | | | |
| Acquisition of Unproved Acreage | 175 | 291 | 343 | 214 | 745 | 565 | 2,159 |
| Geological and Geophysical | 1,127 | 813 | 932 | 843 | 869 | 897 | 1,065 |
| Drilling and Equipping [1] | 1,618 | 1,564 | 1,595 | 2,114 | 2,277 | 2,684 | 2,650 |
| Other [2] | 1,123 | 1,011 | 960 | 989 | 919 | 1,128 | 1,299 |
| Total Exploration | 4,043 | 3,679 | 3,830 | 4,160 | 4,810 | 5,274 | 7,173 |
| **Development** | | | | | | | |
| Acquisition of Proved Acreage | 143 | 407 | 737 | 371 | 1,932 | 1,641 | 7,121 |
| Lease Equipment | 2,382 | 2,476 | 1,329 | 1,537 | 2,064 | 2,207 | 2,505 |
| Drilling and Equipping [1] | 3,842 | 4,118 | 4,085 | 4,535 | 5,278 | 6,426 | 6,206 |
| Other [2] | 2,499 | 1,866 | 1,928 | 2,568 | 2,534 | 2,383 | 3,388 |
| Total Development | 8,866 | 8,867 | 8,079 | 9,011 | 11,808 | 12,657 | 19,220 |
| **Total Foreign Exploration and Development** | 12,909 | 12,546 | 11,909 | 13,171 | 16,618 | 17,931 | 26,393 |

[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).

*Last Updated on 12/20/99*

**Table B15.**
**Components of U.S. and Foreign Exploration and Development Expenditures for FRS Companies, 1998**
(Million Dollars)

| | Worldwide | United States | | | Foreign |
|---|---|---|---|---|---|
| | | Total | Onshore | Offshore | |
| **Exploration and Development Expenditures** | | | | | |
| **Exploration Expenditures** | | | | | |
| Unproved Acreage | 6,071 | 3,912 | 2,256 | 1,656 | 2,159 |
| Drilling and Equipping | | | | | |
| Dry Holes (Cumulative) | - | 1,361 | 338 | 1,023 | - |
| Oil Wells (Cumulative) | - | 346 | 69 | 277 | - |
| Gas Wells (Cumulative) | - | 814 | 303 | 511 | - |
| Work-in-progress Adjustment | - | 443 | 81 | 362 | - |
| Total Drilling and Equipping | 5,614 | 2,964 | 791 | 2,173 | 2,650 |
| Geological and Geophysical | 1,981 | 916 | 367 | 549 | 1,065 |
| Other, Including Direct Overhead | 2,253 | 954 | 527 | 427 | 1,299 |
| Total Exploration Expenditures | 15,919 | 8,746 | 3,941 | 4,805 | 7,173 |
| **Development Expenditures** | | | | | |
| Proved Acreage (Including Mergers and Acquisitions) | 10,689 | 3,568 | 2,413 | 1,155 | 7,121 |
| Drilling and Equipping | | | | | |
| Dry Holes (Cumulative) | - | 361 | 252 | 109 | - |
| Oil Wells (Cumulative) | - | 2,132 | 1,412 | 720 | - |
| Gas Wells (Cumulative) | - | 3,107 | 2,183 | 924 | - |
| Work-in-progress Adjustment | - | 2,169 | 680 | 1,489 | - |
| Total Drilling and Equipping | 13,975 | 7,769 | 4,527 | 3,242 | 6,206 |
| Lease Equipment | 5,193 | 2,688 | 1,357 | 1,331 | 2,505 |
| Other Development | | | | | |
| Support Equipment | 753 | 161 | 136 | 25 | 592 |
| Other, Including Direct Overhead | 4,292 | 1,496 | 1,086 | 410 | 2,796 |
| Total Development Expenditures | 34,902 | 15,682 | 9,519 | 6,163 | 19,220 |
| **Total Exploration and Development Expenditures** | 50,821 | 24,428 | 13,460 | 10,968 | 26,393 |

W = Data withheld to avoid disclosure.

- = Not available.

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

*Last Updated on 12/20/99*

**Table B16.**
**Exploration and Development Expenditures by Region, 1992-1998**
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Exploration Expenditures** | | | | | | | |
| U.S. Onshore | 1,593 | 1,371 | 1,491 | 1,644 | 1,826 | 2,112 | 3,941 |
| U.S. Offshore | 1,082 | 1,415 | 1,897 | 1,866 | 2,827 | 3,602 | 4,805 |
| Total United States | 2,675 | 2,786 | 3,388 | 3,510 | 4,653 | 6,998 | 8,746 |
| Canada | 336 | 403 | 573 | 493 | 355 | 310 | 638 |
| OECD Europe | 1,544 | 1,313 | 1,063 | 1,242 | 1,345 | 1,684 | 1,916 |
| Former Soviet Union and E. Europe | 0 | 163 | 204 | 181 | 194 | 285 | 630 |
| Africa | 738 | 599 | 678 | 707 | 779 | 807 | 1,092 |
| Middle East | 273 | 225 | 104 | 90 | 45 | 53 | 141 |
| Other Eastern Hemisphere | 869 | 736 | 888 | 1,016 | 1,462 | 1,341 | 1,563 |
| Other Western Hemisphere | 283 | 240 | 320 | 431 | 630 | 794 | 1,193 |
| Total Foreign | 4,043 | 3,679 | 3,830 | 4,160 | 4,810 | 5,274 | 7,173 |
| Worldwide Exploration Expenditures | 6,718 | 6,465 | 7,218 | 7,670 | 9,463 | 12,272 | 15,919 |
| **Development Expenditures** | | | | | | | |
| U.S. Onshore | 5,703 | 5,843 | 6,324 | 6,051 | 6,087 | 9,624 | 9,519 |
| U.S. Offshore | 1,936 | 2,303 | 2,876 | 2,873 | 3,892 | 5,224 | 6,163 |
| Total United States | 7,639 | 8,146 | 9,200 | 8,924 | 9,979 | 14,848 | 15,682 |
| Canada | 770 | 1,156 | 1,262 | 1,406 | 1,210 | 1,688 | 4,168 |
| OECD Europe | 5,252 | 4,169 | 3,376 | 3,962 | 4,222 | 5,368 | 6,670 |
| Former Soviet Union and E. Europe | 0 | 100 | 93 | 178 | 267 | 343 | 637 |
| Africa | 655 | 873 | 714 | 1,336 | 2,014 | 2,171 | 2,042 |
| Middle East | 285 | 460 | 341 | 271 | 418 | 590 | 801 |
| Other Eastern Hemisphere | 1,540 | 1,733 | 1,870 | 1,414 | 2,670 | 1,643 | 2,386 |
| Other Western Hemisphere | 364 | 376 | 423 | 444 | 1,007 | 854 | 2,516 |
| Total Foreign | 8,866 | 8,867 | 8,079 | 9,011 | 11,808 | 12,657 | 19,220 |
| Worldwide Development Expenditures | 16,505 | 17,013 | 17,279 | 17,935 | 21,787 | 27,505 | 34,902 |
| **Total Exploration and Development Expenditures** | | | | | | | |
| U.S. Onshore | 7,296 | 7,214 | 7,815 | 7,695 | 7,913 | 13,020 | 13,460 |
| U.S. Offshore | 3,018 | 3,718 | 4,773 | 4,739 | 6,719 | 8,826 | 10,968 |
| Total United States | 10,314 | 10,932 | 12,588 | 12,434 | 14,632 | 21,846 | 24,428 |
| Canada | 1,106 | 1,559 | 1,835 | 1,899 | 1,565 | 1,998 | 4,806 |
| OECD Europe | 6,796 | 5,482 | 4,439 | 5,204 | 5,567 | 7,052 | 8,586 |
| Former Soviet Union and E. Europe | 0 | 263 | 297 | 359 | 461 | 628 | 1,267 |
| Africa | 1,393 | 1,472 | 1,392 | 2,043 | 2,793 | 2,978 | 3,134 |
| Middle East | 558 | 685 | 445 | 361 | 463 | 643 | 942 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Other Eastern Hemisphere | 2,409 | 2,469 | 2,758 | 2,430 | 4,132 | 2,984 | 3,949 |
| Other Western Hemisphere | 647 | 616 | 743 | 875 | 1,637 | 1,648 | 3,709 |
| Total Foreign | 12,909 | 12,546 | 11,909 | 13,171 | 16,618 | 17,931 | 26,393 |
| **Worldwide Exploration and Development Expenditures** | 23,223 | 23,478 | 24,497 | 25,605 | 31,250 | 39,777 | 50,821 |
| Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). | | | | | | | |

*Last Updated on 12/20/99*

# Table B17.
# Production (Lifting) Costs by Region for FRS Companies, 1992-1998
(Million Dollars)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **United States** | | | | | | | |
| Taxes Other Than Income Taxes | 1,967 | 1,906 | 1,719 | 1,693 | 2,098 | 1,965 | 1,176 |
| Other Costs | 12,586 | 11,777 | 11,107 | 10,429 | 10,221 | 10,147 | 9,787 |
| Total Production Costs | 14,553 | 13,683 | 12,826 | 12,122 | 12,319 | 12,112 | 10,963 |
| U.S. Onshore | 12,057 | 11,148 | 10,342 | 9,769 | 9,855 | 9,604 | 8,198 |
| U.S. Offshore | 2,496 | 2,535 | 2,484 | 2,353 | 2,464 | 2,508 | 2,765 |
| **Canada** | | | | | | | |
| Royalty Expenses | W | 19 | W | W | W | W | W |
| Taxes Other Than Income Taxes | W | 56 | W | W | W | W | W |
| Other Costs | 1,388 | 1,210 | 1,141 | 1,082 | 993 | 961 | 1,037 |
| Total Production Costs | 1,464 | 1,285 | 1,234 | 1,174 | 1,082 | 1,049 | 1,129 |
| **OECD Europe** | | | | | | | |
| Royalty Expenses | 465 | 305 | 206 | 235 | 251 | 217 | 251 |
| Taxes Other Than Income Taxes | 257 | 214 | 274 | 311 | 400 | 360 | 269 |
| Other Costs | 4,199 | 3,617 | 4,128 | 4,116 | 3,996 | 3,950 | 3,980 |
| Total Production Costs | 4,921 | 4,136 | 4,608 | 4,662 | 4,647 | 4,527 | 4,500 |
| **Former Soviet Union and E. Europe** | | | | | | | |
| Royalty Expenses | -- | 0 | 0 | 0 | 0 | 0 | 0 |
| Taxes Other Than Income Taxes | -- | 0 | W | W | W | W | W |
| Other Costs | -- | 54 | W | W | W | W | W |
| Total Production Costs | -- | 54 | 65 | 128 | 134 | 192 | 208 |
| **Africa** | | | | | | | |
| Royalty Expenses | 282 | W | W | W | W | W | W |
| Taxes Other Than Income Taxes | 21 | W | W | W | W | W | W |
| Other Costs | 776 | 821 | 740 | 607 | 812 | 861 | 1,194 |
| Total Production Costs | 1,079 | 1,122 | 1,011 | 916 | 1,259 | 1,310 | 1,490 |
| **Middle East** | | | | | | | |
| Royalty Expenses | 62 | W | W | W | W | W | W |
| Taxes Other Than Income Taxes | 292 | W | W | W | W | W | W |
| Other Costs | 324 | 313 | 340 | 258 | 296 | 280 | 250 |
| Total Production Costs | 678 | 424 | 435 | 403 | 483 | 491 | 429 |
| **Other Eastern Hemisphere** | | | | | | | |
| Royalty Expenses and Taxes Other Than Income Taxes | 685 | 630 | 433 | 400 | 542 | 456 | 240 |
| Other Costs | 1,400 | 1,173 | 1,132 | 1,110 | 1,161 | 1,144 | 1,074 |
| Total Production Costs | 2,085 | 1,803 | 1,565 | 1,510 | 1,703 | 1,600 | 1,314 |
| **Other Western Hemisphere** | | | | | | | |
| Royalty Expenses and Taxes Other Than Income Taxes | 137 | 122 | 83 | 129 | 180 | 156 | 87 |
| Other Costs | 450 | 374 | 346 | 428 | 389 | 470 | 552 |
| Total Production Costs | 587 | 496 | 429 | 557 | 569 | 626 | 639 |
| **Total Foreign** | | | | | | | |
| Royalty Expenses | 991 | 789 | 613 | 680 | 901 | 891 | 740 |
| Taxes Other Than Income Taxes | 1,286 | 969 | 843 | 942 | 1,196 | 1,050 | 675 |
| Other Costs | 8,537 | 7,562 | 7,891 | 7,728 | 7,780 | 7,854 | 8,294 |
| Total Production Costs | 10,814 | 9,320 | 9,347 | 9,350 | 9,877 | 9,795 | 9,709 |

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

*Last Updated on 12/20/99*

**Table B18.**
**Oil and Gas Acreage for FRS Companies, 1992-1998**
(Thousand Acres)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Net Acreage** | | | | | | | |
| U.S. Onshore Developed | 29,590 | 28,856 | 28,744 | 27,429 | 26,733 | 25,474 | 26,396 |
| Undeveloped | 44,433 | 42,196 | 35,698 | 38,792 | 31,659 | 31,154 | 30,598 |
| U.S. Offshore Developed | 5,202 | 4,799 | 4,818 | 6,154 | 5,470 | 5,343 | 4,634 |
| Undeveloped | 20,837 | 16,175 | 13,925 | 14,334 | 16,880 | 22,983 | 23,168 |
| Foreign Developed | 26,010 | 22,050 | 20,505 | 18,063 | 22,574 | 21,984 | 24,887 |
| Undeveloped | 578,568 | 500,238 | 444,427 | 449,255 | 445,176 | 472,106 | 514,511 |
| **Gross Acreage** | | | | | | | |
| U.S. Onshore Developed | 53,389 | 50,640 | 51,846 | 50,016 | 46,887 | 45,249 | 49,097 |
| Undeveloped | 68,413 | 65,051 | 57,865 | 61,651 | 53,775 | 55,530 | 51,364 |
| U.S. Offshore Developed | 10,602 | 9,753 | 10,112 | 11,291 | 9,668 | 10,665 | 8,861 |
| Undeveloped | 26,692 | 20,233 | 19,128 | 18,595 | 21,786 | 30,845 | 32,439 |
| Foreign Developed | 85,614 | 61,274 | 57,885 | 49,946 | 59,926 | 58,198 | 64,358 |
| Undeveloped | 1,055,350 | 937,683 | 855,790 | 892,178 | 857,130 | 924,839 | 1,083,355 |

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

*Last Updated on 12/20/99*

# Table B19.
# U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1992-1998

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Number of Net Wells Completed During Year for FRS Companies** | | | | | | | |
| Onshore | | | | | | | |
| Net Exploratory Wells | | | | | | | |
| Dry Holes | 294 | 231 | 175 | 232 | 274 | 163 | 159 |
| Oil Wells | 112 | 108 | 101 | 104 | 91 | 90 | 55 |
| Gas Wells | 127 | 127 | 167 | 201 | 207 | 170 | 142 |
| Total Exploratory Wells | 533 | 466 | 443 | 538 | 572 | 424 | 356 |
| Net Development Wells | | | | | | | |
| Dry Holes | 193 | 236 | 203 | 262 | 319 | 301 | 256 |
| Oil Wells | 1,664 | 1,966 | 1,980 | 1,908 | 2,095 | 3,016 | 2,510 |
| Gas Wells | 1,582 | 1,664 | 1,865 | 2,156 | 2,049 | 2,261 | 2,074 |
| Total Development Wells | 3,439 | 3,865 | 4,048 | 4,326 | 4,463 | 5,577 | 4,841 |
| Offshore | | | | | | | |
| Net Exploratory Wells | | | | | | | |
| Dry Holes | 50 | 69 | 78 | 72 | 84 | 98 | 91 |
| Oil Wells | 21 | 22 | 13 | 32 | 36 | 31 | 22 |
| Gas Wells | 25 | 42 | 47 | 53 | 87 | 73 | 63 |
| Total Exploratory Wells | 95 | 133 | 138 | 157 | 206 | 202 | 176 |
| Net Development Wells | | | | | | | |
| Dry Holes | 19 | 13 | 17 | 18 | 23 | 46 | 32 |
| Oil Wells | 111 | 125 | 150 | 151 | 158 | 181 | 115 |
| Gas Wells | 46 | 98 | 120 | 95 | 153 | 168 | 133 |
| Total Development Wells | 176 | 236 | 287 | 265 | 334 | 396 | 280 |
| Total United States | | | | | | | |
| Net Exploratory Wells | | | | | | | |
| Dry Holes | 344 | 300 | 253 | 304 | 358 | 261 | 249 |
| Oil Wells | 132 | 130 | 114 | 137 | 127 | 121 | 77 |
| Gas Wells | 151 | 169 | 214 | 255 | 293 | 243 | 205 |
| Total Exploratory Wells | 627 | 599 | 581 | 695 | 778 | 626 | 531 |
| Net Development Wells | | | | | | | |
| Dry Holes | 212 | 249 | 220 | 280 | 342 | 347 | 288 |
| Oil Wells | 1,775 | 2,091 | 2,130 | 2,059 | 2,253 | 3,197 | 2,625 |
| Gas Wells | 1,628 | 1,761 | 1,985 | 2,252 | 2,202 | 2,429 | 2,208 |
| Total Development Wells | 3,615 | 4,101 | 4,335 | 4,591 | 4,797 | 5,973 | 5,121 |
| **Number of Net Wells Completed During Year for Total U.S. Industry** | | | | | | | |
| Net Exploratory Wells | | | | | | | |
| Dry Holes | 2,586 | 2,604 | 2,479 | 2,302 | 2,211 | 2,121 | 1,835 |
| Oil Wells | 983 | 876 | 836 | 866 | 825 | 430 | 306 |
| Gas Wells | 883 | 888 | 994 | 992 | 1,051 | 539 | 586 |
| Total Exploratory Wells | 4,452 | 4,367 | 4,309 | 4,160 | 4,087 | 3,091 | 2,727 |
| Net Development Wells | | | | | | | |
| Dry Holes | 3,441 | 3,666 | 2,862 | 2,778 | 2,977 | 3,616 | 3,158 |
| Oil Wells | 7,675 | 7,459 | 5,905 | 6,788 | 7,368 | 10,039 | 6,704 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Gas Wells | 7,225 | 9,079 | 8,517 | 7,284 | 8,093 | 10,784 | 11,580 |
| Total Development Wells | 18,341 | 20,204 | 17,284 | 16,849 | 18,437 | 24,440 | 21,442 |

# Table B19.
# U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1992-1998
(Continued)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Number of Net In-Progress Wells At Year End for FRS Companies** | | | | | | | |
| Onshore | | | | | | | |
| Exploratory Wells | 97 | 106 | 90 | 135 | 133 | 135 | 51 |
| Development Wells | 795 | 709 | 524 | 541 | 675 | 929 | 392 |
| Total In-Progress Wells | 892 | 815 | 614 | 676 | 808 | 1,064 | 444 |
| Offshore | | | | | | | |
| Exploratory Wells | 39 | 35 | 46 | 46 | 45 | 92 | 52 |
| Development Wells | 57 | 68 | 91 | 57 | 93 | 128 | 73 |
| Total In-Progress Wells | 96 | 103 | 137 | 103 | 138 | 220 | 124 |
| Total United States | | | | | | | |
| Exploratory Wells | 136 | 141 | 136 | 181 | 178 | 226 | 103 |
| Development Wells | 852 | 777 | 615 | 598 | 768 | 1,058 | 465 |
| Total In-Progress Wells | 988 | 918 | 751 | 779 | 946 | 1,284 | 568 |

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, September 1999, p. 83. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/20/99*

# Table B20.
# U.S. Net Drilling Footage and Net Producing Wells For FRS Companies and U.S. Industry, 1992-1998
(Thousand Feet)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **FRS Companies** | | | | **(Onshore)** | | | |
| Exploratory Well Footage | | | | | | | |
| Dry Hole Footage | 2,623 | 2,341 | 1,699 | 1,799 | 2,052 | 1,700 | 1,714 |
| Oil Well Footage | 964 | 974 | 796 | 836 | 732 | 1,027 | 406 |
| Gas Well Footage | 1,035 | 1,072 | 1,464 | 1,456 | 1,860 | 1,521 | 1,548 |
| Total Exploratory Footage | 4,622 | 4,387 | 3,959 | 4,091 | 4,644 | 4,248 | 3,668 |
| Development Well Footage | | | | | | | |
| Dry Hole Footage | 1,270 | 1,429 | 1,177 | 1,550 | 2,224 | 1,926 | 1,939 |
| Oil Well Footage | 9,192 | 11,407 | 10,269 | 10,053 | 10,956 | 14,534 | 12,513 |
| Gas Well Footage | 10,589 | 11,558 | 12,955 | 14,468 | 14,304 | 16,751 | 16,521 |
| Total Development Footage | 21,051 | 24,394 | 24,401 | 26,071 | 27,484 | 33,211 | 30,973 |
| Exploratory Well Footage | | | | **(Offshore)** | | | |
| Dry Hole Footage | 755 | 710 | 911 | 891 | 1,091 | 1,362 | 1,345 |
| Oil Well Footage | 275 | 304 | 132 | 408 | 408 | 397 | 443 |
| Gas Well Footage | 321 | 488 | 568 | 702 | 1,824 | 981 | 1,285 |
| Total Exploratory Footage | 1,351 | 1,502 | 1,611 | 2,001 | 3,323 | 2,740 | 3,073 |
| Development Well Footage | | | | | | | |
| Dry Hole Footage | 172 | 158 | 124 | 155 | 244 | 459 | 344 |
| Oil Well Footage | 871 | 1,267 | 1,597 | 1,588 | 1,704 | 1,736 | 1,428 |
| Gas Well Footage | 466 | 975 | 1,025 | 1,011 | 1,538 | 1,584 | 1,398 |
| Total Development Footage | 1,509 | 2,400 | 2,746 | 2,754 | 3,486 | 3,779 | 3,170 |
| **Total United States** | | | | **(Total)** | | | |
| Exploratory Well Footage | | | | | | | |
| Dry Hole Footage | 3,378 | 3,051 | 2,610 | 2,690 | 3,143 | 3,062 | 3,059 |
| Oil Well Footage | 1,239 | 1,278 | 928 | 1,244 | 1,140 | 1,424 | 849 |
| Gas Well Footage | 1,356 | 1,560 | 2,032 | 2,158 | 3,684 | 2,502 | 2,833 |
| Total Exploratory Footage | 5,973 | 5,889 | 5,570 | 6,092 | 7,967 | 6,988 | 6,741 |
| Development Well Footage | | | | | | | |
| Dry Hole Footage | 1,442 | 1,587 | 1,301 | 1,705 | 2,468 | 2,385 | 2,283 |
| Oil Well Footage | 10,063 | 12,674 | 11,866 | 11,641 | 12,660 | 16,270 | 13,941 |
| Gas Well Footage | 11,055 | 12,533 | 13,980 | 15,479 | 15,842 | 18,335 | 17,919 |
| Total Development Footage | 22,560 | 26,794 | 27,147 | 28,825 | 30,970 | 36,990 | 34,143 |
| **Total United States Industry** | | | | **(Total)** | | | |
| Exploratory Well Footage | | | | | | | |
| Dry Hole Footage | 14,204 | 14,752 | 14,570 | 13,562 | 13,648 | 13,627 | 12,167 |
| Oil Well Footage | 5,853 | 5,449 | 5,277 | 5,502 | 5,678 | 3,391 | 2,525 |
| Gas Well Footage | 4,936 | 5,020 | 5,934 | 6,398 | 6,369 | 3,945 | 4,231 |
| Total Exploratory Footage | 24,993 | 25,222 | 25,781 | 25,462 | 25,695 | 20,963 | 18,924 |
| Development Well Footage | | | | | | | |
| Dry Hole Footage | 16,567 | 17,610 | 14,807 | 14,353 | 15,800 | 19,403 | 18,130 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Oil Well Footage | 37,446 | 36,632 | 30,824 | 32,776 | 34,148 | 48,770 | 33,457 |
| Gas Well Footage | 40,696 | 54,846 | 54,066 | 45,098 | 50,766 | 67,532 | 73,034 |
| Total Development Footage | 94,709 | 109,088 | 99,696 | 92,227 | 100,715 | 135,705 | 124,621 |

See footnotes at end of table.

*Last Updated on 12/20/99*

# Table B20.
## U.S. Net Drilling Footage and Net Producing Wells For FRS Companies and U.S. Industry, 1992-1998 (continued)
(Thousand Feet)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Number of Net Producing Wells for FRS Companies** | | | | | | | |
| Onshore | | | | | | | |
| Oil Wells | 112,782 | 106,760 | 105,679 | 94,867 | 87,461 | 75,493 | 69,401 |
| Gas Wells | 46,308 | 46,535 | 49,237 | 50,388 | 48,779 | 48,779 | 49,429 |
| Total Producing Wells | 159,089 | 153,295 | 154,916 | 145,256 | 136,240 | 124,272 | 118,830 |
| Offshore | | | | | | | |
| Oil Wells | 5,021 | 4,274 | 4,179 | 4,180 | 3,552 | 3,760 | 3,421 |
| Gas Wells | 2,709 | 2,643 | 2,895 | 3,042 | 2,556 | 2,898 | 2,737 |
| Total Producing Wells | 7,730 | 6,917 | 7,074 | 7,221 | 6,108 | 6,658 | 6,158 |
| Total United States | | | | | | | |
| Oil Wells | 117,803 | 111,034 | 109,858 | 99,047 | 91,013 | 79,253 | 72,822 |
| Gas Wells | 49,016 | 49,178 | 52,132 | 53,430 | 51,335 | 51,677 | 52,166 |
| Total Producing Wells | 166,819 | 160,212 | 161,990 | 152,477 | 142,348 | 130,930 | 124,987 |

Sources: Well footage, 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 Administration's *Monthly Energy Review*, September 1999, p. 83. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/20/99*

# Table B21.
# Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1992-1998

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| | **Canada** | | | | | | |
| Net Wells Completed During Year | | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 65.1 | 71.7 | 111.2 | 107.5 | 86.2 | 22.8 | 54.8 |
| Oil Wells | 19.7 | 47.9 | 42.0 | 66.6 | 46.0 | 10.7 | 10.0 |
| Gas Wells | 29.6 | 46.8 | 105.1 | 74.0 | 96.1 | 49.2 | 66.3 |
| Total Exploratory Wells | 114.4 | 166.4 | 258.3 | 248.1 | 228.3 | 82.7 | 131.1 |
| Development Wells | | | | | | | |
| Dry Holes | 29.3 | 47.4 | 59.6 | 42.7 | 48.1 | 59.6 | 58.8 |
| Oil Wells | 211.1 | 334.6 | 174.2 | 569.5 | 559.4 | 778.6 | 198.9 |
| Gas Wells | 39.4 | 292.9 | 416.6 | 189.6 | 233.7 | 275.1 | 422.4 |
| Total Development Wells | 279.8 | 674.9 | 650.4 | 801.8 | 841.2 | 1,113.3 | 680.1 |
| Net In-Progress Wells at Year End | 31.7 | 65.3 | 57.6 | 43.1 | 17.2 | 30.6 | 24.3 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 12,597.5 | 11,704.3 | 11,268.5 | 9,793.9 | 8,719.5 | 9,364.7 | 10,532.3 |
| Gas Wells | 5,927.2 | 5,740.2 | 5,953.3 | 5,998.6 | 5,784.8 | 6,199.5 | 8,872.7 |
| Total Producing Wells | 18,524.7 | 17,444.5 | 17,221.8 | 15,792.5 | 14,504.3 | 15,564.2 | 19,405.0 |
| | **Europe and Former Soviet Union [1]** | | | | | | |
| Net Wells Completed During Year | | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 47.4 | 33.4 | 33.7 | 42.1 | 49.4 | 56.6 | 36.3 |
| Oil Wells | 16.2 | 11.8 | 13.3 | 21.4 | 14.5 | 19.2 | 11.8 |
| Gas Wells | 11.8 | 14.6 | 11.2 | 10.6 | 11.4 | 8.9 | 12.0 |
| Total Exploratory Wells | 75.4 | 59.8 | 58.2 | 74.1 | 75.3 | 84.7 | 60.1 |
| Development Wells | | | | | | | |
| Dry Holes | 2.6 | 3.6 | 1.5 | 2.2 | 5.3 | 3.2 | 7.8 |
| Oil Wells | 38.2 | 59.9 | 60.4 | 72.4 | 77.6 | 80.7 | 118.5 |
| Gas Wells | 25.8 | 28.8 | 24.5 | 29.0 | 31.0 | 25.1 | 60.5 |
| Total Development Wells | 66.6 | 92.3 | 86.4 | 103.6 | 113.9 | 109.0 | 186.8 |
| Net In-Progress Wells at Year End | 70.5 | 76.3 | 74.5 | 73.0 | 68.7 | 62.7 | 54.5 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 1,459.3 | 1,479.3 | 1,430.2 | 1,359.4 | 1,445.5 | 1,328.0 | 1,294.4 |
| Gas Wells | 647.5 | 687.0 | 720.7 | 741.9 | 765.2 | 766.8 | 805.3 |
| Total Producing Wells | 2,106.8 | 2,166.3 | 2,150.9 | 2,101.3 | 2,210.7 | 2,094.8 | 2,099.7 |

See footnotes at end of table.

*Last Updated on 12/20/99*

# Table B21.
## Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1992-1998 (Continued)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| Net Wells Completed During Year | **Africa and Middle East** | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 65.3 | 37.9 | 32.0 | 28.4 | 19.8 | 25.3 | 33.1 |
| Oil Wells | 18.1 | W | W | W | W | W | W |
| Gas Wells | W | W | W | W | W | W | W |
| Total Exploratory Wells | 84.8 | 52.8 | 47.9 | 42.8 | 44.0 | 46.1 | 65.0 |
| Development Wells | | | | | | | |
| Dry Holes | W | W | W | W | W | W | W |
| Oil Wells | 91.1 | 72.2 | 105.7 | 109.7 | 133.0 | 151.6 | 218.4 |
| Gas Wells | W | W | W | W | W | W | W |
| Total Development Wells | 103.5 | 81.8 | 117.7 | 119.2 | 144.0 | 157.8 | 225.6 |
| Net In-Progress Wells at Year End | 34.4 | 21.3 | 45.1 | 41.9 | 36.9 | 29.0 | 18.0 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 1,374.1 | 1,322.9 | 1,442.2 | 1,509.0 | 1,688.9 | 1,644.6 | 1,924.2 |
| Gas Wells | 26.8 | 25.8 | 34.4 | 41.9 | 49.9 | 59.5 | 62.7 |
| Total Producing Wells | 1,400.9 | 1,348.7 | 1,476.6 | 1,550.9 | 1,738.8 | 1,704.1 | 1,986.9 |
| Net Wells Completed During Year | **Other Eastern Hemisphere** | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 47.6 | 43.9 | 47.4 | 47.4 | 42.6 | 39.8 | 47.1 |
| Oil Wells | 22.9 | 8.3 | 11.6 | 13.1 | 21.6 | 16.1 | 36.6 |
| Gas Wells | 10.0 | 16.4 | 14.5 | 44.4 | 46.3 | 15.8 | 13.8 |
| Total Exploratory Wells | 80.5 | 68.6 | 73.5 | 104.9 | 110.5 | 71.7 | 97.5 |
| Development Wells | | | | | | | |
| Dry Holes | 11.0 | 8.7 | 5.2 | 1.5 | 3.7 | 4.7 | 11.5 |
| Oil Wells | 106.7 | 124.9 | 115.7 | 92.7 | 103.1 | 162.6 | 149.5 |
| Gas Wells | 71.9 | 62.7 | 45.9 | 32.4 | 91.7 | 116.5 | 101.2 |
| Total Development Wells | 189.6 | 196.3 | 166.8 | 126.6 | 198.5 | 283.8 | 262.2 |
| Net In-Progress Wells at Year End | 71.5 | 83.8 | 71.9 | 92.5 | 72.4 | 61.4 | 64.5 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 1,650.2 | 1,666.0 | 1,714.9 | 1,476.2 | 1,622.0 | 1,767.0 | 1,707.2 |
| Gas Wells | 373.2 | 393.9 | 437.9 | 401.4 | 561.2 | 633.8 | 862.2 |
| Total Producing Wells | 2,023.4 | 2,059.9 | 2,152.8 | 1,877.6 | 2,183.2 | 2,400.8 | 2,569.4 |

See footnotes at end of table.

*Last Updated on 12/20/99*

# Table B21.
## Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1992-1998 (Continued)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| | **Other Western Hemisphere** | | | | | | |
| Net Wells Completed During Year | | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 6.9 | 8.1 | 7.5 | 9.2 | 12.4 | 5.7 | 14.6 |
| Oil Wells | W | W | W | W | W | W | 10.4 |
| Gas Wells | W | W | W | W | W | W | 4.5 |
| Total Exploratory Wells | 12.0 | 19.8 | 15.5 | 13.9 | 23.4 | 10.4 | 29.5 |
| Development Wells | | | | | | | |
| Dry Holes | W | W | W | W | W | W | W |
| Oil Wells | 87.0 | 78.8 | 85.6 | 120.5 | 123.3 | 141.4 | 212.8 |
| Gas Wells | W | W | W | W | W | W | W |
| Total Development Wells | 89.0 | 87.2 | 94.3 | 133.1 | 129.8 | 148.3 | 224.5 |
| Net In-Progress Wells at Year End | 7.4 | 15.6 | 14.8 | 20.2 | 16.1 | 24.4 | 28.9 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 2,938.3 | 3,032.6 | 2,939.6 | 2,980.6 | 2,478.9 | 605.0 | 2,045.6 |
| Gas Wells | 42.0 | 65.4 | 48.7 | 57.6 | 77.3 | 72.2 | 190.9 |
| Total Producing Wells | 2,980.3 | 3,098.0 | 2,988.3 | 3,038.2 | 2,556.2 | 677.2 | 2,236.5 |
| | **Total Foreign** | | | | | | |
| Net Wells Completed During Year | | | | | | | |
| Exploratory Wells | | | | | | | |
| Dry Holes | 232.3 | 195.0 | 231.8 | 234.6 | 210.4 | 150.2 | 185.9 |
| Oil Wells | 81.0 | 93.0 | 88.5 | 119.7 | 110.9 | 71.0 | 97.6 |
| Gas Wells | 53.8 | 79.4 | 133.1 | 129.5 | 160.2 | 74.4 | 99.7 |
| Total Exploratory Wells | 367.1 | 367.4 | 453.4 | 483.8 | 481.5 | 295.6 | 383.2 |
| Development Wells | | | | | | | |
| Dry Holes | 52.2 | 71.1 | 77.2 | 51.9 | 67.9 | 75.5 | 83.7 |
| Oil Wells | 534.1 | 670.4 | 541.6 | 964.8 | 996.4 | 1,314.9 | 898.1 |
| Gas Wells | 142.2 | 391.0 | 496.8 | 267.6 | 363.1 | 421.8 | 597.4 |
| Total Development Wells | 728.5 | 1,132.5 | 1,115.6 | 1,284.3 | 1,427.4 | 1,812.2 | 1,579.2 |
| Net In-Progress Wells at Year End | 215.5 | 262.3 | 263.9 | 270.7 | 211.3 | 208.1 | 190.2 |
| Net Producing Wells | | | | | | | |
| Oil Wells | 20,019.4 | 19,205.1 | 18,795.4 | 17,119.1 | 15,954.8 | 14,709.3 | 17,503.7 |
| Gas Wells | 7,016.7 | 6,912.3 | 7,195.0 | 7,241.4 | 7,238.4 | 7,731.8 | 10,793.8 |
| Total Producing Wells | 27,036.1 | 26,117.4 | 25,990.4 | 24,360.5 | 23,193.2 | 22,441.1 | 28,297.5 |

[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).

*Last Updated on 12/20/99*

# Table B22.
# Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1997 and 1998

| Drilling and Equipping Measures | Total United States | | | U.S. Onshore | | | U.S. Offshore | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1997 | 1998 | Percent Change | 1997 | 1998 | Percent Change | 1997 | 1998 | Percent Change |
| **Exploration** | | | | | | | | | |
| Oil Wells | | | | | | | | | |
| Drilling and Equipping Costs [1] | 502.0 | 346.0 | -31.1 | 167.0 | 69.0 | -58.7 | 335.0 | 277.0 | -17.3 |
| Wells Completed | 121.4 | 76.5 | -37.0 | 90.3 | 55.0 | -39.1 | 31.1 | 21.5 | -30.9 |
| Cost per Well (thousand dollars) | 4,135.0 | 4,523.0 | 9.4 | 1,849.0 | 1,255.0 | -32.2 | 10,772.0 | 12,884.0 | 19.6 |
| Average Depth (thousand feet) | 11.7 | 11.1 | -5.4 | 11.4 | 7.4 | -35.1 | 12.8 | 20.6 | 61.4 |
| Cost per Foot (dollars) | 352.5 | 407.5 | 15.6 | 162.6 | 170.0 | 4.5 | 843.8 | 625.3 | -25.9 |
| Gas Wells | | | | | | | | | |
| Drilling and Equipping Costs [1] | 782.0 | 814.0 | 4.1 | 287.0 | 303.0 | 5.6 | 495.0 | 511.0 | 3.2 |
| Wells Completed | 242.8 | 205.3 | -15.4 | 170.3 | 142.0 | -16.6 | 72.5 | 63.3 | -12.7 |
| Cost per Well (thousand dollars) | 3,221.0 | 3,965.0 | 23.1 | 1,685.0 | 2,134.0 | 26.6 | 6,828.0 | 8,073.0 | 18.2 |
| Average Depth (thousand feet) | 10.3 | 13.8 | 33.9 | 8.9 | 10.9 | 22.1 | 13.5 | 20.3 | 50.0 |
| Cost per Foot (dollars) | 312.6 | 287.3 | -8.1 | 188.7 | 195.7 | 3.7 | 504.6 | 397.7 | -21.2 |
| Dry Holes | | | | | | | | | |
| Drilling and Equipping Costs [1] | 1,005.0 | 1,361.0 | 35.4 | 333.0 | 338.0 | 1.5 | 672.0 | 1,023.0 | 52.2 |
| Wells Completed | 261.4 | 249.4 | -4.6 | 163.1 | 158.5 | -2.8 | 98.3 | 90.9 | -7.5 |
| Cost per Well (thousand dollars) | 3,845.0 | 5,457.0 | 41.9 | 2,042.0 | 2,132.0 | 4.4 | 6,836.0 | 11,254.0 | 64.6 |
| Average Depth (thousand feet) | 11.7 | 12.3 | 4.7 | 10.4 | 10.8 | 3.7 | 13.9 | 14.8 | 6.8 |
| Cost per Foot (dollars) | 328.2 | 444.9 | 35.6 | 195.9 | 197.2 | 0.7 | 493.4 | 760.6 | 54.2 |
| **Development** | | | | | | | | | |
| Oil Wells | | | | | | | | | |
| Drilling and Equipping Costs [1] | 2,715.0 | 2,132.0 | -21.5 | 1,601.0 | 1,412.0 | -11.8 | 1,114.0 | 720.0 | -35.4 |
| Wells Completed | 3,197.0 | 2,625.1 | -17.9 | 3,015.8 | 2,510.1 | -16.8 | 181.2 | 115.0 | -36.5 |
| Cost per Well (thousand dollars) | 849.0 | 812.0 | -4.4 | 531.0 | 563.0 | 6.0 | 6,148.0 | 6,261.0 | 1.8 |
| Average Depth (thousand feet) | 5.1 | 5.3 | 4.4 | 4.8 | 5.0 | 3.4 | 9.6 | 12.4 | 29.6 |
| Cost per Foot (dollars) | 166.9 | 152.9 | -8.4 | 110.2 | 112.8 | 2.4 | 641.7 | 504.2 | -21.4 |
| Gas Wells | | | | | | | | | |
| Drilling and Equipping Costs [1] | 3,086.0 | 3,107.0 | 0.7 | 1,965.0 | 2,183.0 | 11.1 | 1,121.0 | 924.0 | -17.6 |
| Wells Completed | 2,428.9 | 2,207.6 | -9.1 | 2,260.5 | 2,074.4 | -8.2 | 168.4 | 133.2 | -20.9 |
| Cost per Well (thousand dollars) | 1,271.0 | 1,407.0 | 10.8 | 869.0 | 1,052.0 | 21.1 | 6,657.0 | 6,937.0 | 4.2 |
| Average Depth (thousand feet) | 7.5 | 8.1 | 7.5 | 7.4 | 8.0 | 7.5 | 9.4 | 10.5 | 11.6 |
| Cost per Foot (dollars) | 168.3 | 173.4 | 3.0 | 117.3 | 132.1 | 12.6 | 707.7 | 660.9 | -6.6 |
| Dry Holes | | | | | | | | | |
| Drilling and Equipping Costs [1] | 390.0 | 361.0 | -7.4 | 201.0 | 252.0 | 25.4 | 189.0 | 109.0 | -42.3 |
| Wells Completed | 347.1 | 288.0 | -17.0 | 300.8 | 256.2 | -14.8 | 46.3 | 31.8 | -31.3 |
| Cost per Well (thousand dollars) | 1,124.0 | 1,253.0 | 11.6 | 668.0 | 984.0 | 47.2 | 4,082.0 | 3,428.0 | -16.0 |
| Average Depth (thousand feet) | 6.9 | 7.9 | 15.4 | 6.4 | 7.6 | 18.2 | 9.9 | 10.8 | 9.1 |
| Cost per Foot (dollars) | 163.5 | 158.1 | -3.3 | 104.4 | 130.0 | 24.5 | 411.8 | 316.9 | -23.0 |

[1] Million dollars.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/20/99*

# Table B23.
# Oil and Gas Reserves for FRS Companies and U.S. Industry, 1998

| | Beginning Reserves | Plus Reserve Additions [1] | Plus Net Purchases | Less Production | Equals Ending Reserves | Replacement Rate |
|---|---|---|---|---|---|---|
| **Crude Oil and Natural Gas Liquids** | (million barrels) | | | | | (percent) |
| U.S. Onshore | | | | | | |
| Total U.S. Industry | 25,759.0 | 545.0 | 0.0 | 2,224.0 | 24,080.0 | 24.5 |
| FRS Companies | 12,386.7 | 488.9 | 178.9 | 991.4 | 12,063.0 | 49.3 |
| All Other | 13,372.3 | 56.1 | -178.9 | 1,232.6 | 12,017.0 | 4.6 |
| U.S. Offshore | | | | | | |
| Total U.S. Industry | 4,760.0 | 318.0 | 0.0 | 600.0 | 4,478.0 | 53.0 |
| FRS Companies | 3,319.0 | 352.1 | 80.0 | 397.4 | 3,353.7 | 88.6 |
| All Other | 1,441.0 | -34.1 | -80.0 | 202.6 | 1,124.3 | -16.8 |
| U.S. Total | | | | | | |
| Total U.S. Industry | 30,519.0 | 863.0 | 0.0 | 2,824.0 | 28,558.0 | 30.6 |
| FRS Companies | 15,705.7 | 840.9 | 259.0 | 1,388.8 | 15,416.8 | 60.6 |
| All Other | 14,813.3 | 22.1 | -259.0 | 1,435.2 | 13,141.2 | 1.5 |
| **FRS Companies' Foreign Oil Reserves** | | | | | | |
| Canada | 1,857.0 | 69.5 | 235.4 | 172.6 | 1,989.4 | 40.3 |
| Europe | 4,473.4 | 285.8 | 229.7 | 559.3 | 4,429.6 | 51.1 |
| FSU and Eastern Europe | 475.9 | W | W | 22.6 | 499.1 | W |
| Africa | 3,418.2 | W | W | 320.4 | 4,093.0 | W |
| Middle East | 996.4 | 167.1 | 2.8 | 130.3 | 1,036.0 | 128.2 |
| Other Eastern Hemisphere | 1,652.8 | 322.8 | 90.5 | 251.1 | 1,814.9 | 128.5 |
| Other Western Hemisphere | 791.2 | 561.9 | 265.7 | 89.8 | 1,529.1 | 625.8 |
| Total Foreign | 13,665.0 | 2,377.8 | 894.4 | 1,546.1 | 15,391.0 | 153.8 |
| Worldwide Total for FRS Companies | 29,370.6 | 3,218.7 | 1,153.4 | 2,934.9 | 30,807.7 | 109.7 |
| **Dry Natural Gas** | (billion cubic feet) | | | | | (percent) |
| U.S. Onshore | | | | | | |
| Total U.S. Industry | 137,687.0 | 12,125.0 | 0.0 | 13,616.0 | 136,196.0 | 89.0 |
| FRS Companies | 54,571.4 | 5,807.5 | 224.7 | 5,493.1 | 55,110.5 | 105.7 |
| All Other | 83,115.6 | 6,317.5 | -224.7 | 8,122.9 | 81,085.5 | 77.8 |
| U.S. Offshore | | | | | | |
| Total U.S. Industry | 29,536.0 | 3,413.0 | 0.0 | 5,104.0 | 27,845.0 | 66.9 |
| FRS Companies | 19,769.0 | 2,588.0 | 934.7 | 2,902.7 | 20,389.0 | 89.2 |
| All Other | 9,767.0 | 825.0 | -934.7 | 2,201.3 | 7,456.0 | 37.5 |
| U.S. Total | | | | | | |
| Total U.S. Industry | 167,223.0 | 15,538.0 | 0.0 | 18,720.0 | 164,041.0 | 83.0 |
| FRS Companies | 74,340.5 | 8,395.5 | 1,159.4 | 8,395.9 | 75,499.5 | 100.0 |
| All Other | 92,882.5 | 7,142.5 | -1,159.4 | 10,324.1 | 88,541.5 | 69.2 |
| **FRS Companies' Foreign Gas Reserves** | | | | | | |
| Canada | 7,377.9 | 833.0 | 1,616.3 | 868.5 | 8,958.6 | 95.9 |
| Europe | 23,715.2 | 1,136.2 | 384.8 | 2,081.6 | 23,154.7 | 54.6 |
| FSU and Eastern Europe | 102.6 | W | W | 11.4 | 343.4 | W |
| Africa | 802.4 | 1,036.2 | 0.0 | 34.4 | 1,804.2 | 3,009.5 |
| Middle East | 495.5 | W | W | 96.5 | 644.1 | W |
| Other Eastern Hemisphere | 22,048.5 | 1,917.9 | 906.6 | 1,702.5 | 23,170.6 | 112.7 |
| Other Western Hemisphere | 9,125.6 | W | W | 386.8 | 11,274.1 | W |
| Total Foreign | 63,667.7 | 7,541.9 | 3,321.9 | 5,181.8 | 69,349.7 | 145.5 |
| Worldwide Total for FRS Companies | 138,008.2 | 15,937.4 | 4,481.3 | 13,577.6 | 144,849.2 | 117.4 |

[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*, 1997 and 1998 (December 1998 and November 1999). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/17/99*

## Table B24.
## Oil and Gas Reserve Balances by Region for FRS Companies, 1998

| Reserves Statistics | Worldwide Total | United States Total | United States Onshore | United States Offshore | Total Foreign |
|---|---|---|---|---|---|
| | (million barrels) | | | | |
| **Crude Oil and Natural Gas Liquids** | | | | | |
| Beginning of Period | 29,371 | 15,706 | 12,387 | 3,319 | 13,665 |
| Revisions of Previous Estimates | 507 | 42 | -84 | 125 | 465 |
| Improved Recovery | 563 | 297 | 297 | 0 | 265 |
| Purchases of Minerals-in-Place | 1,850 | 705 | 570 | 135 | 1,144 |
| Extensions & Discoveries | 2,150 | 502 | 276 | 226 | 1,647 |
| Production | -2,935 | -1,389 | -991 | -397 | -1,546 |
| Sales of Minerals-in-Place | -696 | -446 | -391 | -55 | -250 |
| End of period | 30,808 | 15,417 | 12,063 | 3,354 | 15,391 |
| Proportionate Interest in Investee Reserves and Foreign Access Reserves | 3,393 | -- | -- | -- | 3,393 |
| | (billion cubic feet) | | | | |
| **Natural Gas Reserves** | | | | | |
| Beginning of Period | 138,008 | 74,340 | 54,571 | 19,769 | 63,668 |
| Revisions of Previous Estimates | 2,112 | 1,329 | 1,148 | 181 | 782 |
| Improved Recovery | 549 | 338 | 332 | 6 | 211 |
| Purchases of Minerals-in-Place | 8,238 | 3,871 | 2,568 | 1,303 | 4,367 |
| Extensions & Discoveries | 13,277 | 6,728 | 4,328 | 2,400 | 6,549 |
| Production | -13,578 | -8,396 | -5,493 | -2,903 | -5,182 |
| Sales of Minerals-in-Place | -3,757 | -2,712 | -2,343 | -369 | -1,045 |
| End of Period | 144,849 | 75,500 | 55,111 | 20,389 | 69,350 |
| Proportionate Interest in Investee Reserves and Foreign Access Reserves | 21,389 | -- | -- | -- | 21,389 |

See footnotes at end of table.

*Last Updated on 12/20/99*

# Table B24.
# Oil and Gas Reserve Balances by Region for FRS Companies,1998 (Continued)

| Reserves Statistics | Foreign | | | | | |
|---|---|---|---|---|---|---|
| | Total | Canada | Europe and Former Soviet Union [1] | Africa and Middle East | Other Eastern Hemisphere | Other Western Hemisphere |
| | (million barrels) | | | | | |
| **Crude Oil and Natural Gas Liquids** | | | | | | |
| Beginning of Period | 13,665 | 1,857 | 4,949 | 4,415 | 1,653 | 791 |
| Revisions of Previous Estimates | 465 | -75 | 90 | 397 | 68 | -16 |
| Improved Recovery | 265 | 42 | 67 | 147 | 9 | 0 |
| Purchases of Minerals-in-Place | 1,144 | 293 | 317 | W | W | W |
| Extensions & Discoveries | 1,647 | 102 | 117 | 606 | 245 | 578 |
| Production | -1,546 | -173 | -582 | -451 | -251 | -90 |
| Sales of Minerals-in-Place | -250 | -57 | -29 | W | W | W |
| End of period | 15,391 | 1,989 | 4,929 | 5,129 | 1,815 | 1,529 |
| Proportionate Interest in Investee Reserves and Foreign Access Reserves | 3,393 | W | 1,802 | 861 | W | W |
| | (billion cubic feet) | | | | | |
| **Natural Gas Reserves** | | | | | | |
| Beginning of Period | 63,668 | 7,378 | 23,818 | 1,298 | 22,048 | 9,126 |
| Revisions of Previous Estimates | 782 | -117 | 536 | 194 | 252 | -83 |
| Improved Recovery | 211 | 66 | 106 | W | W | 0 |
| Purchases of Minerals-in-Place | 4,367 | 1,930 | 874 | W | W | W |
| Extensions & Discoveries | 6,549 | 883 | 496 | 923 | 1,666 | 2,581 |
| Production | -5,182 | -869 | -2,093 | -131 | -1,702 | -387 |
| Sales of Minerals-in-Place | -1,045 | -314 | -238 | 0 | -493 | 0 |
| End of Period | 69,350 | 8,959 | 23,498 | 2,448 | 23,171 | 11,274 |
| Proportionate Interest in Investee Reserves and Foreign Access Reserves | 21,389 | W | 18,323 | W | W | 0 |

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

*Last Updated on 12/20/99*

## Table B25.
## Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1998

| | United States | | | |
|---|---|---|---|---|
| | Total | Onshore | Offshore | Foreign Total |
| **Exploration and Development Expenditures** (million dollars) | | | | |
| FRS Companies | 24,428.0 | 13,460.0 | 10,968.0 | 26,393.0 |
| Percent Change | 11.8 | 3.4 | 24.3 | 47.2 |
| **Wells Completed** | | | | |
| FRS Companies | 5,651.9 | 5,196.2 | 455.7 | 1,962.4 |
| Percent Change | -14.3 | -13.4 | -23.8 | -6.9 |
| Industry[1] | 24,169.0 | 23,559.0 | 610.0 | 16,597.0 |
| Percent Change | -12.2 | -12.1 | -17.6 | -24.1 |
| **Success Rate**[2] | | | | |
| FRS Companies | 90.5 | 92.0 | 73.1 | 86.3 |
| Industry[1] | 79.3 | 80.0 | 52.5 | 83.3 |
| **Crude Oil and NGL Production**[3] (million barrels) | | | | |
| FRS Companies | 1,388.8 | 991.4 | 397.4 | 1,792.3 |
| Percent Change | -4.8 | -9.5 | 9.5 | 19.2 |
| Industry [1] | 2,824.0 | 2,224.0 | 600.0 | 22,595.6 |
| Percent Change | -5.9 | -7.9 | 2.2 | 1.9 |
| **Crude Oil and NGL Reserve Interests**[4] (million barrels) | | | | |
| FRS Companies | 15,416.8 | 12,063.0 | 3,353.7 | 18,784.5 |
| Percent Change | -1.8 | -2.6 | 1.0 | 10.2 |
| **Production** (billion cubic feet) | | | | |
| FRS Companies | 8,395.9 | 5,493.1 | 2,902.7 | 5,138.8 |
| Percent Change | 1.2 | 0.8 | 1.9 | 4.8 |
| Industry[1] | 18,720.0 | 13,616.0 | 5,104.0 | 60,250.3 |
| Percent Change | -2.6 | -1.3 | -5.7 | 3.1 |
| **Natural Gas Reserve Interests** (billion cubic feet) | | | | |
| FRS Companies | 75,499.5 | 55,110.5 | 20,389.0 | 90,738.5 |
| Percent Change | 2.6 | 2.4 | 3.1 | 6.5 |

See footnotes at end of table.

*Last Updated on 12/17/99*

## Table B25.
## Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1998 (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 | 26,393.0 | 4,806.0 | 9,853.0 | 3,134.0 | 942.0 | 3,949.0 | 3,709.0 |
| Percent Change | 47.2 | 140.5 | 28.3 | 5.2 | 46.5 | 32.3 | 125.1 |
| **Wells Completed** | | | | | | | |
| FRS Companies | 1,962.4 | 811.2 | 246.9 | 146.9 | 143.7 | 359.7 | 254.0 |
| Percent Change | -6.9 | -32.2 | 27.5 | 6.6 | 117.4 | 1.2 | 60.1 |
| Foreign Industry[1] | 16,597.0 | 9,589.0 | 1,225.0 | 743.0 | 692.0 | 1,902.0 | 2,446.0 |
| Percent Change | -24.1 | -33.5 | -1.2 | -0.7 | -6.5 | 13.5 | -19.5 |
| **Success Rate**[2] (percent) | | | | | | | |
| FRS Companies | 86.3 | 86.0 | 82.1 | 82.2 | 92.3 | 83.7 | 93.7 |
| Foreign Industry[1] | 83.3 | 80.8 | 78.6 | 79.4 | 94.9 | 83.4 | 92.9 |
| **Crude Oil and NGL Production**[3] (million barrels) | | | | | | | |
| FRS Companies | 1,792.3 | 172.6 | 566.9 | 565.4 | 146.4 | 251.1 | 89.8 |
| Percent Change | 19.2 | 24.5 | -2.1 | 82.9 | 17.3 | -5.4 | 4.6 |
| Foreign Industry[1] | 22,595.6 | 974.6 | 5,199.5 | 2,746.7 | 8,320.2 | 1,620.6 | 3,734.0 |
| Percent Change | 1.9 | 4.3 | -0.6 | -3.3 | 4.9 | -0.3 | 3.4 |
| **Crude Oil and NGL Reserve Interests**[4] (million barrels) | | | | | | | |
| FRS Companies | 18,784.5 | 2,031.2 | 6,730.4 | 4,091.6 | 1,897.9 | 2,502.2 | 1,531.1 |
| Percent Change | 10.2 | 6.9 | -1.8 | 19.7 | -0.9 | 18.7 | 79.4 |
| **Natural Gas Production** (billion cubic feet) | | | | | | | |
| FRS Companies | 5,138.8 | 868.5 | 2,050.0 | 34.4 | 96.5 | 1,702.5 | 386.8 |
| Percent Change | 4.8 | 17.2 | 1.0 | 102.7 | 5.6 | -0.5 | 23.0 |
| Foreign Industry[1] | 60,250.3 | 5,644.5 | 32,425.9 | 3,573.8 | 6,392.0 | 7,903.4 | 4,290.7 |
| Percent Change | 3.1 | 2.0 | 2.2 | 7.6 | 8.6 | 2.6 | 0.6 |
| **Natural Gas Reserve Interests** (billion cubic feet) | | | | | | | |
| FRS Companies | 90,738.5 | 9,096.2 | 41,820.8 | 1,804.2 | 3,421.4 | 23,321.8 | 11,274.1 |
| Percent Change | 6.5 | 20.6 | -1.7 | 124.9 | 3.8 | 5.0 | 28.3 |

[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.

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*, 1997, and 1998 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, September 1999, p. 83. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 1999 and 1998.* Wells Completed, Foreign - *World Oil*, August 1999 and 1998. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/17/99*

# Table B26.
# U.S. and Foreign Refining/Marketing Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies,1992-1998 (million barrels)

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **U.S. Refining/Marketing** | | | | | | | |
| Sources | | | | | | | |
| Acquisitions from U.S. Production Segment | 1,745 | 1,743 | 2,014 | 1,658 | 1,599 | 1,542 | 1,484 |
| Purchases from Other U.S. Segments and Unconsolidated Affiliates | 679 | 607 | 385 | 432 | 459 | 468 | 1,935 |
| Purchases from Third Parties | 3,883 | 3,925 | 3,937 | 4,100 | 4,488 | 4,444 | 4,968 |
| Net Transfers from Foreign Refining/Marketing Segment | 869 | 757 | 754 | 612 | 566 | 571 | 635 |
| Total Sources | 7,176 | 7,032 | 7,090 | 6,802 | 7,112 | 7,025 | 9,021 |
| Dispositions | | | | | | | |
| Net Change in Inventories | -8 | 31 | 48 | 23 | 21 | 14 | 31 |
| Input to Refineries | 3,611 | 3,565 | 3,636 | 3,565 | 3,563 | 3,259 | 4,883 |
| Sales to: | | | | | | | |
| Unaffiliated Third Parties | 3,171 | 3,261 | 3,235 | 2,961 | 3,291 | 3,424 | 3,730 |
| Other Segments Excluding Foreign Refining/Marketing | 401 | 175 | 172 | 252 | 237 | 328 | 377 |
| Total Dispositions | 7,176 | 7,032 | 7,090 | 6,802 | 7,112 | 7,025 | 9,021 |
| **Foreign Refining/Marketing** | | | | | | | |
| Sources | | | | | | | |
| Acquisitions from Foreign Production Segment | 1,150 | 1,163 | 1,335 | 1,249 | 1,371 | 1,391 | 1,380 |
| Purchases | | | | | | | |
| Other Foreign Segments | 77 | 85 | 95 | 93 | 88 | W | W |
| Unconsolidated Affiliates | 79 | 2 | 63 | 89 | 89 | W | W |
| Unaffiliated Third Parties | | | | | | | |
| Foreign Access | 111 | 114 | 120 | 107 | 145 | 228 | 209 |
| Foreign Governments (Open Market) | 774 | 725 | 726 | 621 | 844 | 851 | 679 |
| Other Unaffiliated Third Parties | 1,885 | 2,653 | 2,147 | 2,063 | 1,819 | 1,785 | 2,000 |
| Net Transfers to U.S. Refining/Marketing Segment | -869 | -757 | -754 | -612 | -566 | -571 | -635 |
| Total Sources | 3,207 | 3,986 | 3,731 | 3,610 | 3,790 | 3,699 | 4,021 |
| Dispositions | | | | | | | |
| Net Change in Inventories | -8 | -1 | 0 | 1 | 38 | 18 | 155 |
| Input to Refineries | 1,367 | 1,530 | 1,535 | 1,520 | 1,605 | 1,435 | 1,419 |
| Sales | 1,849 | 2,456 | 2,195 | 2,090 | 2,147 | 2,246 | 2,446 |
| Total Dispositions | 3,207 | 3,986 | 3,731 | 3,610 | 3,790 | 3,699 | 4,021 |

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

*Last Updated on 12/20/99*

# Table B27.
# U.S. Purchases and Sales of Oil, Natural Gas, Other Raw Materials, and Refined Products, 1992-1998

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Purchases** | | | | Values (million dollars) | | | |
| U.S. Refining/Marketing Segment | | | | | | | |
| Raw Materials | | | | | | | |
| Crude Oil and NGL | 124,868 | 111,654 | 104,471 | 111,556 | 138,397 | 126,535 | 106,128 |
| Natural Gas | 7,504 | 10,678 | 12,360 | 9,747 | 15,651 | 18,657 | 15,177 |
| Other Raw Materials | 2,496 | 3,196 | 3,498 | 3,892 | 2,697 | 3,159 | 5,348 |
| Total Raw Materials | 134,868 | 125,528 | 120,329 | 125,195 | 156,745 | 148,351 | 126,653 |
| Refined Products | | | | | | | |
| Motor Gasoline | 12,403 | 11,831 | 12,430 | 14,131 | 18,078 | 18,613 | 24,249 |
| Distillate Fuels | 6,008 | 6,629 | 6,626 | 6,773 | 9,634 | 9,565 | 10,574 |
| Other Refined Products | 9,261 | 8,467 | 8,389 | 10,114 | 10,246 | 9,141 | 8,786 |
| Total Refined Products | 27,672 | 26,927 | 27,445 | 31,018 | 37,958 | 37,319 | 43,609 |
| U.S. Production Segment | | | | | | | |
| Crude Oil and NGL | 2,816 | 2,458 | 2,660 | 3,353 | 5,163 | 5,399 | 4,694 |
| Natural Gas | 4,192 | 5,042 | 5,950 | 6,981 | 10,715 | 11,220 | 8,922 |
| Total Raw Materials | 7,008 | 7,500 | 8,610 | 10,334 | 15,878 | 16,619 | 13,616 |
| **Sales** | | | | | | | |
| U.S. Refining/Marketing Segment | | | | | | | |
| Raw Materials | | | | | | | |
| Crude Oil and NGL | 63,564 | 56,612 | 49,752 | 53,544 | 69,485 | 70,437 | 50,702 |
| Natural Gas | 7,406 | 10,527 | 12,432 | 9,295 | 15,790 | 18,252 | 15,270 |
| Other Raw Materials | 1,175 | 1,720 | 2,201 | 2,325 | 1,276 | 1,499 | 2,172 |
| Total Raw Materials | 72,145 | 68,859 | 64,385 | 65,164 | 86,551 | 90,188 | 68,144 |
| Refined Products | | | | | | | |
| Motor Gasoline | 67,695 | 63,476 | 61,032 | 65,701 | 75,330 | 71,185 | 85,187 |
| Distillate Fuels | 33,920 | 33,064 | 30,568 | 30,420 | 41,618 | 36,962 | 39,161 |
| Other Refined Products | 22,525 | 21,107 | 23,190 | 24,577 | 24,577 | 20,964 | 23,108 |
| Total Refined Products | 124,140 | 117,647 | 114,790 | 120,698 | 141,525 | 129,111 | 147,456 |
| U.S. Production Segment | | | | | | | |
| Crude Oil and NGL | 29,585 | 25,734 | 23,468 | 26,303 | 32,948 | 30,604 | 19,688 |
| Natural Gas | 16,905 | 20,238 | 19,757 | 18,696 | 26,840 | 29,459 | 23,649 |
| Total Raw Materials | 46,490 | 45,972 | 43,225 | 44,999 | 59,788 | 60,063 | 43,337 |
| **Purchases** | | | | Volumes | | | |
| U.S. Refining/Marketing Segment | | | | | | | |
| Raw Materials | | | | | | | |
| Crude Oil and NGL (million barrels) | 7,176 | 7,032 | 7,090 | 6,802 | 7,112 | 7,025 | 9,021 |
| Natural Gas (billion cubic feet) | 4,593 | 6,022 | 7,479 | 6,543 | 7,506 | 7,573 | 7,191 |
| Refined Products (million barrels) | | | | | | | |
| Motor Gasoline | 467 | 487 | 563 | 588 | 677 | 689 | 1,272 |
| Distillate Fuels | 253 | 288 | 322 | 321 | 380 | 397 | 625 |
| Other Refined Products | 410 | 378 | 345 | 422 | 363 | 329 | 464 |
| Total Refined Products | 1,129 | 1,153 | 1,230 | 1,330 | 1,420 | 1,415 | 2,361 |
| U.S. Production Segment | | | | | | | |
| Crude Oil and NGL (million barrels) | 206 | 178 | 201 | 237 | 300 | 308 | 394 |
| Natural Gas (billion cubic feet) | 2,408 | 2,569 | 3,276 | 4,395 | 4,723 | 4,551 | 4,295 |
| **Sales** | | | | | | | |
| U.S. Refining/Marketing Segment | | | | | | | |
| Raw Materials | | | | | | | |
| Crude Oil and NGL (million barrels) | 3,572 | 3,436 | 3,406 | 3,213 | 3,528 | 3,752 | 4,107 |
| Natural Gas (billion cubic feet) | 4,198 | 5,416 | 6,960 | 6,089 | 7,195 | 7,242 | 6,764 |
| Refined Products (million barrels) | | | | | | | |
| Motor Gasoline | 2,286 | 2,327 | 2,347 | 2,422 | 2,488 | 2,371 | 3,809 |
| Distillate Fuels | 1,364 | 1,400 | 1,392 | 1,374 | 1,562 | 1,473 | 2,150 |
| Other Refined Products | 1,128 | 1,082 | 1,172 | 1,183 | 1,069 | 1,008 | 1,363 |
| Total Refined Products | 4,778 | 4,810 | 4,911 | 4,979 | 5,119 | 4,852 | 7,322 |
| U.S. Production Segment | | | | | | | |
| Crude Oil and NGL (million barrels) | 2,044 | 1,898 | 1,889 | 1,875 | 1,933 | 1,860 | 1,805 |
| Natural Gas (billion cubic feet) | 9,712 | 9,801 | 10,810 | 12,108 | 12,281 | 12,421 | 11,765 |

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

*Last Updated on 12/20/99*

# Table B28.
# U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1992-1998

| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **U.S. Refining** | (thousand barrels per calendar day) | | | | | | |
| Runs to Stills | | | | | | | |
| At Own Refineries | 9,736 | 9,676 | 9,809 | 9,669 | 9,777 | 9,060 | 13,699 |
| By Refineries of Others | 5 | 5 | 5 | 5 | 5 | 5 | 0 |
| Total Runs to Stills | 9,741 | 9,681 | 9,814 | 9,674 | 9,782 | 9,065 | 13,699 |
| Refinery Output at Own Refineries and Refineries of Others | | | | | | | |
| Reformulated Motor Gasoline | - | - | - | - | 1,302 | 768 | 1,552 |
| Oxygenated Motor Gasoline | - | - | - | - | 165 | 749 | 1,018 |
| Other Motor Gasoline | - | - | - | - | 3,410 | 2,980 | 4,665 |
| Total Motor Gasoline | 4,968 | 4,953 | 4,936 | 4,849 | 4,877 | 4,497 | 7,235 |
| Distillate Fuels | 2,931 | 2,916 | 3,030 | 2,901 | 3,323 | 2,921 | 4,278 |
| Other Refined Products | 3,095 | 2,953 | 2,846 | 2,902 | 2,754 | 2,612 | 3,416 |
| Total Refinery Output | 10,994 | 10,822 | 10,812 | 10,652 | 10,954 | 10,030 | 14,929 |
| Refinery Capacity at End of Year | 10,952 | 10,714 | 10,642 | 10,427 | 10,477 | 9,410 | 14,277 |
| | (number of refineries) | | | | | | |
| Number of Wholly-Owned Refineries | 82 | 75 | 74 | 69 | 69 | 60 | 95 |
| | (thousand barrels per calendar day) | | | | | | |
| **Foreign Refining** | | | | | | | |
| Runs to Stills | | | | | | | |
| At Own Refineries | 3,706 | 3,823 | 3,829 | 3,962 | 3,936 | 3,961 | 4,043 |
| By Refineries of Others | 749 | 312 | 304 | 323 | 506 | 340 | 292 |
| Total Runs to Stills | 4,455 | 4,135 | 4,133 | 4,285 | 4,442 | 4,301 | 4,335 |
| Refinery Output at Own Refineries | | | | | | | |
| Motor Gasoline | 1,098 | 1,114 | 1,122 | 1,175 | 1,172 | 1,041 | 1,135 |
| Distillate Fuels | 1,553 | 1,634 | 1,674 | 1,662 | 1,690 | 1,648 | 1,787 |
| Other Refined Products | 1,064 | 1,148 | 1,102 | 1,183 | 1,280 | 1,283 | 1,213 |
| Total Refinery Output at Own Refineries | 3,715 | 3,896 | 3,898 | 4,020 | 4,142 | 3,972 | 4,135 |
| Refinery Output at Refineries of Others | | | | | | | |
| Motor Gasoline | 199 | 85 | 85 | 70 | 107 | 75 | 83 |
| Distillate Fuels | 359 | 136 | 140 | 140 | 234 | 154 | 121 |
| Other Refined Products | 192 | 88 | 82 | 113 | 165 | 110 | 87 |
| Total Refinery Output at Refineries of Others | 750 | 309 | 307 | 323 | 506 | 339 | 291 |
| Total Refinery Output | 4,465 | 4,205 | 4,205 | 4,343 | 4,648 | 4,311 | 4,426 |
| Refinery Capacity at End of Year | 4,648 | 4,692 | 4,766 | 4,450 | 4,346 | 4,270 | 4,508 |
| | (number of refineries) | | | | | | |
| Number of Wholly-Owned Refineries | 27 | 26 | 26 | 24 | 20 | 20 | 20 |
| Number of Partially-Owned Refineries | 14 | 14 | 14 | 13 | 12 | 15 | 15 |

- = Not available.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/20/99*

## Table B29.
## U.S. and Foreign Refinery Output and Capacity for FRS Companies, Ranked by Total Energy Assets, and Industry, 1998
(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] | 14,929 | 3,345 | 3,807 | 7,777 | 17,500 | 85.3 |
| Percent Gasoline | | | | | | |
| Reformulated/Oxygenated | 17.2 | 27.9 | 10.2 | 16.0 | 14.9 | 98.9 |
| Other | 31.2 | 16.4 | 38.9 | 33.9 | 31.3 | 85.2 |
| Percent Distillate | 28.7 | 26.8 | 31.0 | 28.3 | 29.6 | 82.6 |
| Percent Other | 22.9 | 28.8 | 19.8 | 21.8 | 24.2 | 80.5 |
| Refinery Capacity | | | | | | |
| Years Change (Net) | 4,867 | -345 | -559 | 5,771 | 438 | (5) |
| At Year End | 14,277 | 2,970 | 3,547 | 7,760 | 16,567 | 86.2 |
| Utilization Rate[4] | 115.7 | 85.9 | 93.8 | 152.0 | 94.0 | (5) |
| **Foreign** | | | | | | |
| Refinery Output Volume[3] | 4,426 | 3,735 | - | 691 | - | - |
| Percent Gasoline | 27.5 | 26.5 | - | 33.3 | - | - |
| Percent Distillate | 43.1 | 42.9 | - | 44.1 | - | - |
| Percent Other | 29.4 | 30.6 | - | 22.6 | - | - |
| Refinery Capacity | | | | | | |
| Years Change (Net) | 238 | 23 | - | 215 | 145 | (5) |
| At Year End | 4,508 | 3,820 | - | 688 | 64,285 | 7.0 |
| Utilization Rate[3] | 92.1 | 90.0 | - | 106.3 | - | (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,* 1997 and 1998. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy*, 1998 and 1999. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 12/17/99*

# Table B30. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1992-1998

| U.S. Dispositions | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Motor Gasoline** | Values (million dollars) | | | | | | |
| Intersegment Sales | 231 | 196 | 268 | 365 | 400 | 581 | 1,335 |
| U.S. Third-Party Sales | | | | | | | |
| Wholesale-Resellers | 26,641 | 24,954 | 24,923 | 27,386 | 32,500 | 31,895 | 43,303 |
| Company Operated Automotive Outlets | 12,049 | 11,018 | 9,694 | 10,088 | 11,293 | 11,855 | 15,483 |
| Company Lessee and Open Automotive Outlets | 23,061 | 21,917 | 20,948 | 20,494 | 21,725 | 20,517 | 19,567 |
| Other (Industrial, Commercial and Other Retail) | 5,713 | 5,391 | 5,199 | 7,368 | 9,412 | 6,337 | 5,499 |
| Total Third-Party Sales | 67,464 | 63,280 | 60,764 | 65,336 | 74,930 | 70,604 | 83,852 |
| Total Motor Gasoline Sales | 67,695 | 63,476 | 61,032 | 65,701 | 75,330 | 71,185 | 85,187 |
| **Distillate Fuels** | | | | | | | |
| Intersegment Sales | 550 | 440 | 211 | 219 | 291 | 191 | 750 |
| Third-Party Sales | 33,370 | 32,624 | 30,357 | 30,201 | 41,327 | 36,771 | 38,411 |
| Total Distillate Fuels Sales | 33,920 | 33,064 | 30,568 | 30,420 | 41,618 | 36,962 | 39,161 |
| **Other Refined Products** | | | | | | | |
| Intersegment Sales | 4,671 | 4,213 | 3,824 | 3,952 | 4,124 | 3,322 | 2,206 |
| Third-Party Sales | 17,854 | 16,894 | 19,366 | 20,625 | 20,453 | 17,642 | 20,902 |
| Total Other Refined Products Sales | 22,525 | 21,107 | 23,190 | 24,577 | 24,577 | 20,964 | 23,108 |
| **Total U.S. Refined Products** | | | | | | | |
| Intersegment Sales | 5,452 | 4,849 | 4,303 | 4,536 | 4,815 | 4,094 | 4,291 |
| Third-Party Sales | 118,688 | 112,798 | 110,487 | 116,162 | 136,710 | 125,017 | 143,165 |
| Total U.S. Refined Products Sales | 124,140 | 117,647 | 114,790 | 120,698 | 141,525 | 129,111 | 147,456 |
| **Motor Gasoline** | Volumes (million barrels) | | | | | | |
| Intersegment Sales | 9 | 9 | 9 | 11 | 12 | 18 | 70 |
| U.S. Third-Party Sales | | | | | | | |
| Wholesale-Resellers | 972 | 1,012 | 1,064 | 1,117 | 1,154 | 1,150 | 2,134 |
| Company Operated Automotive Outlets | 350 | 342 | 308 | 309 | 319 | 335 | 558 |
| Company Lessee and Open Automotive Outlets | 740 | 731 | 736 | 680 | 653 | 615 | 752 |
| Other (Industrial, Commercial and Other Retail) | 216 | 233 | 229 | 304 | 350 | 253 | 295 |
| Total Third-Party Sales | 2,277 | 2,318 | 2,338 | 2,411 | 2,476 | 2,353 | 3,739 |
| Total Motor Gasoline Sales | 2,286 | 2,327 | 2,347 | 2,422 | 2,488 | 2,371 | 3,809 |
| **Distillate Fuels** | | | | | | | |
| Intersegment Sales | 24 | 20 | 11 | 11 | 12 | 8 | 42 |
| Third-Party Sales | 1,340 | 1,380 | 1,381 | 1,363 | 1,550 | 1,464 | 2,109 |
| Total Distillate Fuels Sales | 1,364 | 1,400 | 1,392 | 1,374 | 1,562 | 1,473 | 2,150 |
| **Other Refined Products** | | | | | | | |
| Intersegment Sales | 232 | 240 | 226 | 222 | 209 | 254 | 162 |
| Third-Party Sales | 896 | 843 | 946 | 961 | 860 | 755 | 1,201 |
| Total Other Refined Products Sales | 1,128 | 1,082 | 1,172 | 1,183 | 1,069 | 1,008 | 1,363 |
| **Total U.S. Refined Products** | | | | | | | |
| Intersegment Sales | 264 | 269 | 246 | 245 | 232 | 280 | 274 |
| Third-Party Sales | 4,513 | 4,541 | 4,665 | 4,734 | 4,886 | 4,572 | 7,048 |
| Total U.S. Refined Products Sales | 4,778 | 4,810 | 4,911 | 4,979 | 5,119 | 4,852 | 7,322 |
| **Number of Active Automobile Outlets at Year End** | Number of Automotive Outlets | | | | | | |
| Company Operated | 9,935 | 9,021 | 8,755 | 8,549 | 8,927 | 8,942 | 13,645 |
| Lessee Dealers | 19,334 | 18,588 | 16,385 | 15,861 | 15,247 | 12,852 | 16,535 |
| Open Dealers | 17,297 | 16,088 | 15,320 | 13,950 | 14,151 | 11,959 | 18,567 |
| Total Outlets | 46,566 | 43,697 | 40,460 | 38,360 | 38,325 | 33,753 | 48,747 |

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

*Last Updated on 12/20/99*

## Table B31.
## Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1997-1998
(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 | | | | | | | | |
| 1998 | 70.0 | 19.06 | 18.3 | 20.57 | W | W | 51.7 | 18.51 |
| 1997 | 18.2 | 31.97 | 16.6 | 31.91 | W | W | W | W |
| Percent Change | 285.5 | -40.40 | 10.3 | -35.50 | W | W | W | W |
| Wholesale/Resellers | | | | | | | | |
| 1998 | 2,133.7 | 20.30 | 443.4 | 20.53 | 435.8 | 21.09 | 1,254.5 | 19.93 |
| 1997 | 1,150.1 | 27.73 | 452.6 | 28.13 | 483.2 | 27.55 | 214.3 | 27.32 |
| Percent Change | 85.5 | -26.80 | -2.0 | -27.00 | -9.8 | -23.40 | 485.4 | -27.00 |
| Dealer-Operated Outlets | | | | | | | | |
| 1998 | 752.4 | 26.01 | 262.8 | 25.99 | 221.0 | 25.71 | 268.6 | 26.26 |
| 1997 | 614.7 | 33.38 | 272.7 | 34.06 | 307.7 | 33.24 | 34.3 | 29.20 |
| Percent Change | 22.4 | -22.10 | -3.6 | -23.70 | -28.2 | -22.60 | 682.6 | -10.00 |
| Company-Operated Outlets | | | | | | | | |
| 1998 | 557.7 | 27.76 | 86.1 | 30.03 | 189.5 | 28.17 | 282.1 | 26.80 |
| 1997 | 335.1 | 35.37 | 95.4 | 36.69 | 166.9 | 33.75 | 72.8 | 37.36 |
| Percent Change | 66.4 | -21.50 | -9.8 | -18.20 | 13.6 | -16.50 | 287.4 | -28.30 |
| Other [1] | | | | | | | | |
| 1998 | 295.4 | 18.62 | 21.4 | 18.62 | 110.9 | 18.57 | 163.0 | 18.65 |
| 1997 | 253.1 | 25.03 | 59.4 | 28.52 | 113.6 | 23.47 | 80.1 | 24.67 |
| Percent Change | 16.7 | -25.60 | -63.9 | -34.70 | -2.4 | -20.90 | 103.6 | -24.40 |
| **Total Gasoline** | | | | | | | | |
| 1998 | 3,809.2 | 22.36 | 832.0 | 23.19 | 957.3 | 23.27 | 2,019.8 | 21.60 |
| 1997 | 2,371.2 | 30.02 | 896.7 | 30.94 | 1,071.9 | 29.72 | 402.5 | 28.78 |
| Percent Change | 60.6 | -25.50 | -7.2 | -25.00 | -10.7 | -21.70 | 401.8 | -25.00 |
| **Distillate** | | | | | | | | |
| 1998 | 2,150.3 | 18.21 | 515.3 | 18.11 | 563.9 | 18.98 | 1,071.1 | 17.86 |
| 1997 | 1,472.8 | 25.10 | 567.6 | 24.99 | 617.8 | 25.22 | 287.3 | 25.04 |
| Percent Change | 46.0 | -27.40 | -9.2 | -27.50 | -8.7 | -24.80 | 272.8 | -28.70 |
| **All Other Products** | | | | | | | | |
| 1998 | 1,362.9 | 16.95 | 320.7 | 19.25 | 257.2 | 17.29 | 785.1 | 15.91 |
| 1997 | 1,008.3 | 20.79 | 315.1 | 24.52 | 423.4 | 17.96 | 269.8 | 20.88 |
| Percent Change | 35.2 | -18.50 | 1.8 | -21.50 | -39.2 | -3.70 | 191.0 | -23.80 |
| **Total Refined Products** | | | | | | | | |
| 1998 | 7,322.4 | 20.14 | 1,667.9 | 20.86 | 1,778.5 | 21.04 | 3,876.0 | 19.41 |
| 1997 | 4,852.2 | 26.61 | 1,779.5 | 27.90 | 2,113.1 | 26.05 | 959.6 | 25.44 |
| Percent Change | 50.9 | -24.30 | -6.3 | -25.20 | -15.8 | -19.20 | 303.9 | -23.70 |

[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).

*Last Updated on 12/20/99*

## Table B32.
## U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1992-1998
(Million Dollars)

| Revenues and Costs | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Refined Product Revenues** | 124,140 | 117,647 | 114,790 | 120,698 | 141,525 | 129,111 | 147,456 |
| **Refined Product Costs** | | | | | | | |
| Raw Materials Processed [1] | 63,629 | 58,161 | 58,025 | 62,142 | 70,339 | 58,888 | 59,159 |
| Refinery Energy Expense | 5,363 | 5,636 | 4,702 | 4,101 | 5,480 | 5,005 | 5,322 |
| Other Refinery Expense | 9,040 | 8,889 | 8,854 | 8,854 | 9,882 | 8,436 | 12,338 |
| Product Purchases | 27,672 | 26,927 | 27,445 | 31,018 | 37,958 | 37,319 | 43,609 |
| Other Product Supply Expense | 3,739 | 4,153 | 3,432 | 3,432 | 4,072 | 3,777 | 5,160 |
| Marketing Expense [2] | 12,895 | 10,463 | 8,822 | 8,709 | 9,318 | 8,538 | 10,308 |
| Total Refined Product Costs | 122,338 | 114,229 | 111,280 | 118,256 | 137,049 | 121,963 | 135,896 |
| **Refined Product Margin** | 1,802 | 3,418 | 3,510 | 2,442 | 4,476 | 7,148 | 11,560 |
| **Refined Products Sold** (million barrels) | 4,777.6 | 4,810.0 | 4,911.0 | 4,978.8 | 5,118.6 | 4,852.2 | 7,322.4 |
| **Dollars per Barrel Margin** [3] | 0.38 | 0.71 | 0.71 | 0.49 | 0.87 | 1.47 | 1.58 |
| **Other Refining/Marketing Revenues** [4] | 10,007 | 10,614 | 10,586 | 10,449 | 10,731 | 9,693 | 16,308 |
| **Other Refining/Marketing Expenses** | | | | | | | |
| DD&A | 3,532 | 3,659 | 3,780 | 4,732 | 3,847 | 3,674 | 4,700 |
| Other [5] | 8,151 | 7,796 | 7,454 | 7,166 | 7,873 | 8,419 | 16,419 |
| Total Other Expenses | 11,683 | 11,455 | 11,234 | 11,898 | 11,720 | 12,093 | 21,119 |
| **Refining/Marketing Operating Income** | 126 | 2,577 | 2,862 | 993 | 3,487 | 4,748 | 6,749 |
| **Miscellaneous Revenue & Expense** [6] | -115 | 207 | 289 | -107 | -101 | 204 | 1,313 |
| **Less Income Taxes** | 217 | 1,099 | 1,306 | 371 | 1,135 | 1,876 | 2,142 |
| **Refining/Marketing Net Income** | -213 | 1,685 | 1,845 | 508 | 2,251 | 3,106 | 5,904 |

[1]Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.
[2]Excludes costs of nofuel goods and services and 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 of transportation services supplied to others, 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).

*Last Updated on 12/20/99*

# Table B33.
## U.S. Petroleum Refining/Marketing General Operating Expenses for FRS Companies, 1992-1998
(Million Dollars)

| General Operating Expenses | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Raw Material Supply** | | | | | | | |
| Raw Material Purchases | 134,868 | 125,528 | 120,329 | 125,195 | 156,745 | 148,351 | 126,653 |
| Other Raw Material Supply Expense | 4,298 | 5,084 | 5,014 | 4,699 | 4,067 | 4,523 | 4,340 |
| Total Raw Material Supply Expense | 139,166 | 130,612 | 125,343 | 129,894 | 160,812 | 152,874 | 130,993 |
| Less: Cost of Raw Materials Input To Refining | 69,115 | 60,989 | 59,336 | 64,086 | 75,892 | 64,132 | 62,955 |
| Net Raw Material Supply | 70,051 | 69,623 | 66,007 | 65,808 | 84,920 | 88,742 | 68,038 |
| **Refining** | | | | | | | |
| Raw Materials Input to Refining | 69,115 | 60,989 | 59,336 | 64,086 | 75,892 | 64,132 | 62,955 |
| Less: Raw Material Used as Refinery Fuel | 3,392 | 3,592 | 2,933 | 2,588 | 3,922 | 3,798 | 3,690 |
| Refinery Process Energy Expense | 5,363 | 5,636 | 4,702 | 4,101 | 5,480 | 5,005 | 5,322 |
| Other Refining Operating Expenses | 9,943 | 9,803 | 9,658 | 9,551 | 10,631 | 9,173 | 13,103 |
| Refined Product Purchases | 27,672 | 26,927 | 27,445 | 31,018 | 37,958 | 37,319 | 43,609 |
| Other Refined Product Supply Expenses | 3,739 | 4,153 | 3,432 | 3,432 | 4,072 | 3,777 | 5,160 |
| Total Refining | 112,440 | 103,916 | 101,640 | 109,600 | 130,111 | 115,608 | 126,459 |
| **Marketing** | | | | | | | |
| Cost of Other Products Sold | 4,609 | 4,734 | 4,074 | 4,389 | 5,449 | 6,255 | 6,844 |
| Other Marketing Expenses | 12,895 | 10,463 | 8,822 | 8,709 | 9,318 | 8,538 | 10,308 |
| Subtotal | 17,504 | 15,197 | 12,896 | 13,098 | 14,767 | 14,793 | 17,152 |
| Expense of Transport Services for Others | 1,140 | 950 | 1,125 | 627 | 507 | 376 | 5,140 |
| Total Marketing | 18,644 | 16,147 | 14,021 | 13,725 | 15,274 | 15,169 | 22,292 |
| **Total U.S. Refining/Marketing Segment General Operating Expenses** | 201,135 | 189,686 | 181,668 | 189,133 | 230,305 | 219,519 | 216,789 |

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

*Last Updated on 12/20/99*

# Table B34.
## U.S. Coal Reserves Balance for FRS Companies, 1992-1998
(Million Tons)

| Reserves and Production Statistics | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
|---|---|---|---|---|---|---|---|
| **Changes to U.S. Coal Reserves** | | | | | | | |
| Beginning of Period | 39,026 | 18,593 | 16,142 | 13,395 | 10,493 | 9,410 | 7,502 |
| Changes due to: | | | | | | | |
| Leases/Purchases of Minerals-in-Place | 571 | 145 | W | W | W | W | W |
| Corporate Mergers and Acquisitions | W | 0 | W | W | W | W | W |
| Other Reserve Changes | W | -325 | -61 | -699 | 8 | -127 | W |
| Production | 252 | 197 | 180 | 165 | 169 | 163 | 74 |
| Dispositions of Minerals-in-Place | -18,576 | -2,074 | -2,591 | -2,128 | -1,150 | -774 | -2,113 |
| End of Period Reserves | 20,787 | 16,142 | 13,381 | 10,493 | 9,542 | 8,498 | 5,334 |
| **Weighted Average Annual Production Capacity** | 291 | 236 | 201 | 184 | 192 | 215 | 65 |
| **Reserves and Production:** | | | | | | | |
| **Total United States** | | | | | | | |
| FRS Companies' Reserves | 20,787 | 16,142 | 13,381 | 10,493 | 9,542 | 8,498 | 5,334 |
| FRS Companies' Production | 252 | 197 | 180 | 165 | 169 | 163 | 74 |
| U.S. Industry Production | 994 | 941 | 1,029 | 1,028 | 1,059 | 1,085 | 1,113 |
| **Region** | | | | | | | |
| **East** | | | | | | | |
| FRS Companies' Reserves | 4,190 | 2,946 | 2,833 | 2,763 | 2,675 | 2,477 | 1,774 |
| FRS Companies' Production | 75 | 41 | 46 | 46 | 44 | 43 | 24 |
| U.S. Industry Production | 453 | 405 | 441 | 430 | 447 | 463 | 455 |
| **Midwest** | | | | | | | |
| FRS Companies' Reserves | 4,733 | 3,673 | 3,212 | 3,206 | 2,467 | 2,080 | 1,372 |
| FRS Companies' Production | 23 | 14 | 16 | 17 | 18 | 17 | 12 |
| U.S. Industry Production | 132 | 107 | 121 | 109 | 112 | 112 | 110 |
| **West** | | | | | | | |
| FRS Companies' Reserves | 11,864 | 9,523 | 7,336 | 4,524 | 4,400 | 3,940 | 2,188 |
| FRS Companies' Production | 154 | 143 | 118 | 103 | 107 | 104 | 38 |
| U.S. Industry Production | 409 | 429 | 467 | 489 | 500 | 511 | 548 |
| **Mining Method** | | | | | | | |
| **Underground** | | | | | | | |
| FRS Companies' Reserves | 8,127 | 6,068 | 5,479 | 5,337 | 4,571 | 3,880 | 2,352 |
| FRS Companies' Production | 84 | 53 | 59 | 62 | 59 | 51 | 28 |
| U.S. Industry Production | 407 | 351 | 399 | 396 | 409 | 420 | 417 |
| **Surface** | | | | | | | |
| FRS Companies' Reserves | 12,660 | 10,074 | 7,902 | 5,156 | 4,970 | 4,618 | 2,982 |
| FRS Companies' Production | 168 | 145 | 121 | 103 | 110 | 112 | 46 |
| U.S. Industry Production | 587 | 591 | 630 | 633 | 650 | 665 | 696 |

W = Data withheld to avoid disclosure.
Sources: Industry data - Energy Information Administration Form EIA-7A, see Coal Industry Annual 1998 (November 1999). FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

*Last Updated on 10/29/99*

# Appendix C

# Completed Foreign Direct Investment Transactions, 1997

### Table C1. Completed Transactions by Size in the Petroleum Industry from January 1997 Through December 1997 - Acquisitions and Divestitures

| Parent Company Acquiring Company | Acquiring Company Activity | Affected Company | Affected Company Activity | Type of Transaction | Size of Transaction (million dollars) | Date of Transaction |
|---|---|---|---|---|---|---|
| | | | **Acquisitions** | | | |
| **Statoil** (Norway) The Eastern Group | Oil and gas exploration and production | Blazer Energy | Oil and gas exploration and production | Merger | 566.0 | July |
| **S A Louis Dreyfus et Cie** (France) Louis Dreyfus Natural Gas | Oil and gas exploration and production | American Exploration | Oil and gas exploration and production | Merger | 350.0 | October |
| **Petroleos de Venezuela** (Venezuela) | National petroleum company | Uno-Ven | Petroleum refining | Equity acquisition | 250.0 | May |
| **Forcenergy** (Sweden) Forcenergy | Oil and gas exploration and production | Edisto Resources Corp/Convest Energy | Oil and gas exploration and production | Merger | 168.0 | October |
| **Transcanadian Pipelines** (Canada) | Natural gas gathering, transmission | Enron Louisiana Energy | Natural gas gathering and transmission | Merger | 150.0 | March |
| **Norex Industries** (British West Indies) DI Industries | Drilling services | Gray Wolf Drilling | Drilling services | Merger | 109.2 | March |
| **British-Borneo Petroleum** (United Kingdom) | Oil and gas exploration and production | Allegeny Field Development | Oil and gas exploration and production | Equity acquisition | 37.5 | August |
| **Norex Industries** (British West Indies) DI Industries | Drilling services | Justiss Drilling | Drilling services | Asset acquisition | 36.1 | September |
| **Coflexip** (France) | NA | Cal Dive International | Drilling services | Equity acquisition | 35.0 | April |
| **Norex Industries** (British West Indies) DI Industries | Drilling services | Fournoy Drilling | Drilling services | Asset acquisition | 31.9 | January |
| **Alliance Resources** (United Kingdom) | Oil and gas exploration and production | LaTex Resources | Oil and gas exploration and production | Merger | 27.1 | February |
| **Norex Industries** (British West Indies) DI Industries | Drilling services | Cactus Drill | Drilling services | Asset acquisition | 25.4 | September |
| **Royal Dutch/Shell** (Netherlands/United Kingdom) Shell Canada | Oil and gas exploration and production | Coral Energy | Oil and gas exploration and production | Equity acquisition | Undisclosed | June |
| **Victoria Petroleum** (Australia) Victoria Petroleum (USA) | Oil and gas exploration and production | Ampolex (USA) | Oil and gas exploration and production | Property acquisition | Undisclosed | April |
| **Westcoast Energy** (Canada) | Natural gas marketing | Coastal | Integrated petroleum operations | Joint venture | Undisclosed | February |
| | | | **Divestitures** | | | |
| Ultramar Diamond Shamrock | Petroleum refining, products | **Total Compagnie Francaise** (France) Total Petroleum (North America) | Oil and gas exploration and production | Equity acquisition | 823.7 | September |

*Last Updated on 10/22/99*

## Table C1. Completed Transactions by Size in the Petroleum Industry from January 1997 Through December 1997 - 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 |
|---|---|---|---|---|---|---|
| Meridian Resources | Oil and gas exploration and production | **Cairn Energy** (United Kingdom) Cairn Energy USA | Oil and gas exploration and production | Merger | 234.0 | November |
| Blackstone Group | Investment banking | **TrizecHahn** (Canada) Clark USA | Petroleum refining | Equity acquisition | 135.0 | November |
| Meridian Resources | Oil and gas exploration and production | **Royal Dutch/Shell** (Netherlands/United Kingdom) Shell Oil | Oil and gas exploration and production | Property acquisition | 42.5 | November |
| Santa Fe Energy Resources | Oil and gas exploration and production | **S A Louis Dreyfus et Cie** (France) Louis Dreyfus Natural Gas | Oil and gas exploration and production | Property acquisition | 27.5 | June |
| Plains Resources | Oil and gas exploration and production | **Royal Dutch/Shell** (Netherlands/United Kingdom) Shell Oil | Oil and gas exploration and production | Property acquisition | 23.3 | November |
| Callon Petroleum | Oil and gas exploration and production | **Elf Acquitaine** (France) Elf Exploration | Oil and gas exploration and production | Property acquisition | 12.5 | July |
| Eott Energy Partners | Oil and gas investment holdings | **Petroleos de Venezuela** (Venezuela) Citgo Petroleum | Petroleum refining, products | Asset acquisition | Undisclosed | February |
| Gothic Energy | Oil and gas exploration and production | **Petrofina** (Belgium) Fina Oil & Chemical | Oil and gas exploration and production | Property acquisition | Undisclosed | May |
| Victoria Petroleum (USA) | Oil and gas exploration and production | **Ampolex** (Australia) Ampolex (USA) | Oil and gas exploration and production | Property acquisition | Undisclosed | April |

Sources: *The Wall Street Journal*, various issues, 1997 and 1998; *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 & Gas Journal*, various issues, 1997 and 1998, Pennwell Publishing, Tulsa, OK; *The Merger Yearbook U.S./International Edition* 1998, Securities Data, New York, NY; *Oil and Gas Investor*, September 1997 and March 1998, Hart Publications, Denver, CO.

*Last Updated on 10/22/99*

**Table C2. Completed Transactions by Size in the Coal Industry from January 1997 Through December 1997- Acquisitions and Divestitures**

| Parent Company Acquiring Company | Acquiring Company Activity | Affected Company | Affected Company Activity | Type of Transaction | Size of Transaction (million dollars) | Date of Transaction |
|---|---|---|---|---|---|---|
| | | | **Acquisitions** | | | |
| **RTZ** (United Kingdom) Kennecott Energy | Coal Mining | Marigold Land | Coal mining | Asset acquisition | 99.0 | February |
| **Mitsubishi** (Japan) | Metals, machinery, groceries | Cyprus Plateau Mining | Coal mining | Equity acquisition | Undisclosed | October |
| | | | **Divestiture** | | | |
| **Rencoal** | Coal Mining | **Costain Group** (United Kingdom) | Investment holdings | Property acquisition | 47.0 | January |

Sources: *The Merger Yearbook U.S./International Edition* 1998, Securities Data Company, New York, NY; *Coal,* various issues, 1997 and 1998, Maclean Hunter Publishing Co., Chicago, IL; company press releases.

*Last Updated on 10/22/99*

**Table C3. Completed Transactions by Size in Other Energy Industries from January 1997 Through December 1997 - Acquisitions and Divestitures**

| Parent Company Acquiring Company | Acquiring Company Activity | Affected Company | Affected Company Activity | Type of Transaction | Size of Transaction (million dollars) | Date of Transaction |
|---|---|---|---|---|---|---|
| | | | **Acquisitions** | | | |
| **Nova** (Canada) NGC | Natural gas transmission, marketing | Destec Energy | Electric power generation | Merger | 1,270.0 | December |
| **The Energy Group** (United Kingdom) Peabody Holding | Investment holdings, coal mining | Citizens Lehman Power | Electric utility | Asset acquisition | 120.0 | May |
| | | | **Divestitures** | | | |
| AES Corp | Electric power generation | **Nova** (Canada) NGC | Natural gas transmission, marketing | Asset acquisition | 439.0 | June |
| Investor Group | NA | **Kuwait Petroleum** Santa Fe Geothermal | Geothermal steam services | Equity acquisition | 89.0 | April |

Sources: *The Wall Street Journal*, various issues, 1997 and 1998; *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 & Gas Journal*, various issues, 1997 and 1998, Pennwell Publishing, Tulsa, OK; *The Merger Yearbook U.S./International Edition* 1997, Securities Data, New York, NY; *Oil and Gas Investor*, September 1997 and April 1998, Hart Publications, Denver, CO; *U.S. Oil Week*, various issues, 1997 and 1998, Capital Publishing, Alexandria, VA; company press releases.

*Last Updated on 10/22/99*

# Glossary

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**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 Appalachian Coal Basin. The following States comprise the Eastern Region: Alabama, eastern Kentucky, Georgia, Ohio, Maryland, Mississippi, Pennsylvania, Virginia, Tennessee, North Carolina, and West Virginia.
- **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, West Coast Coal Basins, and Western Interior. The following States comprise the 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. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation.

**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, blended to form a fuel suitable for use in aviation reciprocating engines. Fuel specifications are provided in ASTM Specification D 910 and Military Specification MIL-G-5572. *Note:* Data on blending components are not counted in data on finished aviation gasoline.

- **Reformulated Motor Gasoline.** Finished motor gasoline formulated 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 211(k) of the Clean Air Act. *Note:* This category includes oxygenated fuels program reformulated gasoline (OPRG) but excludes reformulated gasoline blendstock for oxygenate blending (RBOB).

- **Oxygenated Gasoline.** Finished motor gasoline, other than reformulated gasoline, having an oxygen content of 2.7 percent or higher by weight and required by the U.S. Environmental Protection Agency (EPA) to be sold in areas designated by EPA as carbon monoxide (CO) nonattainment areas. (See the definition for Nonattainment Areas.) *Note:* Oxygenated gasoline excludes oxygenated fuels program reformulated gasoline (OPRG) and reformulated gasoline blendstock for oxygenate blending (RBOB). Data on gasohol that has at least 2.7 percent oxygen, by weight, and is intended for sale inside CO nonattainment areas are included in data on oxygenated gasoline. Other data on gasohol are included in data on conventional gasoline.
- **Other Finished Gasoline.** Motor Gasoline not included in the oxygenated or reformulated gasoline categories.

**Motor Gasoline, Finished Gasohol:** A blend of finished motor gasoline containing alcohol (generally ethanol but sometimes methanol) at a concentration of 10 percent or less by volume. Data on gasohol that has at least 2.7 percent oxygen, by weight, and is intended for sale inside carbon monoxide nonattainment areas are included in data on oxygenated gasoline. (See definition for Oxygenates).

**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.

**Nonattainment Area:** Any area that does not meet the national primary or secondary ambient air quality standard established by the Environmental Protection Agency for designated pollutants, such as carbon monoxide and ozone.

**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:** Substances which, when added to gasoline, increase the amount of oxygen in that gasoline blend. Ethanol, Methyl Tertiary Butyl Ether (MTBE), Ethyl Tertiary Butyl Ether (ETBE), and methanol are common oxygenates.

- **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, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975 and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore powerplants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.

**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.