DOE/EIA-0600
Distribution Category UC-950

Oil and Gas Development in the United States in the Early 1990's: An Expanded Role for Independent Producers

October 1995

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

Contacts

This report was prepared in the Office of Energy Markets and End Use of the Energy Information Administration, U.S. Department of Energy, under the general direction of W. Calvin Kilgore. The project was directed by Mark E. Rodekohr, Director of the Energy Markets and Contingency Information Division (202) 586-1441, and Mary E. Northup, Chief of the Financial Analysis Branch (202) 586-1445. Specific technical information concerning this report may be obtained from Jon A. Rasmussen (202) 586-1449 or Marie N. Fagan (202) 586-1452.

Contents

Tables

Figures

Highlights

Since the oil price collapse of late 1985 and early 1986, the U.S. oil and gas industry has changed dramatically. The major oil companies have shifted much of their exploration and development efforts to targets outside the United States. Although hundreds of nonmajor oil and gas producers were casualties of the price collapse, the survivors became more important players in the industry. Investment by the nonmajors in U.S. oil and gas resource development increased from about 33 percent of total U.S. exploration and development expenditures in 1988-1990 to nearly 50 percent in recent years.

The increasing dependence of U.S. oil and gas development on the typically much smaller nonmajor companies raises a number of issues, which are analyzed in this report. Did those companies gain prominence by default, or have they been significantly adding to the U.S. reserve base? What are the characteristics of surviving producers compared with companies that exited the industry? Do the nonmajors add reserves at higher cost than the majors, or possibly pay more for borrowed funds?

To identify areas of growth of nonmajor oil and gas producers in the context of the entire U.S. industry, this analysis first distinguishes companies as major versus nonmajor petroleum companies. The analysis draws heavily on data from the Energy Information Administration's (EIA) Financial Reporting System, as well as relying on data from EIA's oil and gas reserves report series.

In order to further analyze the corporate features of the nonmajors, the companies are further classified by characteristics such as degree of specialization and corporate structure. In particular, the companies specializing in oil and gas production, generally termed the "independents," were the ones mainly responsible for the nonmajors' growth in oil and gas production. This report uses publicly available company data to evaluate financial results and arrive at conclusions about the independents' standing in the capital markets.

The oil price collapse provides a backdrop to assess the effectiveness of corporate strategy and the influence of investor evaluations on independent oil and gas producers. The analysis highlights the differences in resource development and financial results for firms that survived the oil price collapse and firms that did not survive. Comparison to the majors offers an additional benchmark of financial and operating performance.

Chief findings of this report include:

- *Offshore Gas Led Upswing in Nonmajors' Production Post-1986*. The nonmajors' production of natural gas from offshore locales more than doubled in absolute terms, from 741 billion cubic feet in 1986 to 1,526 billion cubic feet in 1993. This mainly reflected reserve additions, but stepped-up depletion rates also contributed to increased production.

- *Onshore Oil Focus of Growth for Nonmajors*. The nonmajors' share of U.S. oil production from the onshore lower 48 increased from 45 percent (835 million barrels) in 1989 to 54 percent (935 million barrels) in 1993, due to increased production and exit of the majors from these areas.

- *Surviving Independents' Reserve Replacement Costs are Now Similar to Majors.* The cost of reserve replacement (including purchases) for the surviving independents decreased over the 1986-1993 period, and by the 1990's was almost equal to that of the majors at about $5 per barrel. However, the overall cost of exploring for and developing oil and gas reserves (which does not include purchases) was higher for the surviving independents than for the majors, even into the 1990's.

- *Capital Markets Primarily Value Low Cost Reserve Replacement*. The publicly traded independent producers that survived through 1993 tended to incur lower costs in replacing reserves than those companies that exited the U.S. oil and gas industry. And, in spite of greater reliance on debt and lower returns than the majors, the publicly traded independents' cost of capital is comparable to the majors'. This finding indicates that the market has tended to value low cost resource development more than conventional measures of financial performance.

1. Introduction

As the major oil companies have shifted their upstream investment commitments to targets outside the United States, other, typically smaller companies have become more prominent in U.S. oil and gas production. Between the collapse of oil prices in 1986 and 1989, U.S.-based major petroleum companies' (see box entitled "Defining the Majors, Nonmajors, and Independents") foreign exploration and development expenditures nearly doubled, while their U.S. expenditures declined by 14 percent. Since 1991, the majors' foreign exploration and development expenditures have exceeded their U.S. exploration and development expenditures. Costs, fiscal regimes, regulations, and other factors directly affecting profitability, as well as geology and attitudes toward foreign investment, all contributed to this shift in investment.[1]

Although the majors' primary upstream (exploration, development, and production) investment targets shifted abroad, the reduced role for the majors in U.S. oil and gas production did not become strongly apparent until the 1990's (Figure 1). Reductions in spending and production by other U.S. producers responding to the oil price collapse of 1986 and its aftermath, together with lags inherent between exploration and development activity and production accounted for this delay. Also, the majors did not become net sellers of U.S. oil and gas reserves until the 1990's.[2] After the late 1980's, the role of other producers increased. Their share of combined U.S. oil and gas production (crude oil equivalent (COE)),[3] on a net ownership basis,[4] rose from 39 percent in the 1986-1988 period to 45 percent in 1993.

Investment exhibited an even sharper upward trend. Producers other than the majors accounted for only about a third of total U.S. exploration and development expenditures in 1988-1990.[5] In recent years, the comparable share has risen to nearly 50 percent.

The increasing dependence of U.S. oil and gas development on the typically much smaller nonmajor companies raises a number of issues. Did those companies gain increased prominence largely through the reduced commitments of the majors or have they been significantly adding to the U.S. reserve base? What are the characteristics of surviving and growing producers compared with companies exiting the U.S. oil and gas business? Differences between the majors' development strategies and those of other U.S. oil and gas producers appear considerable.[6] As the mix of exploration and

[1]For detailed reviews of these factors, see Energy Information Administration, *Performance Profiles of Major Energy Producers*, 1991 and 1993 issues, DOE/EIA-0206 (Washington, DC, 1992 and 1995), Chapters 3 and 7, respectively.

[2]Energy Information Administration, *Performance Profiles of Major Energy Producers 1993*, DOE/EIA-0206(93) (Washington, DC, January 1995), p. 16.

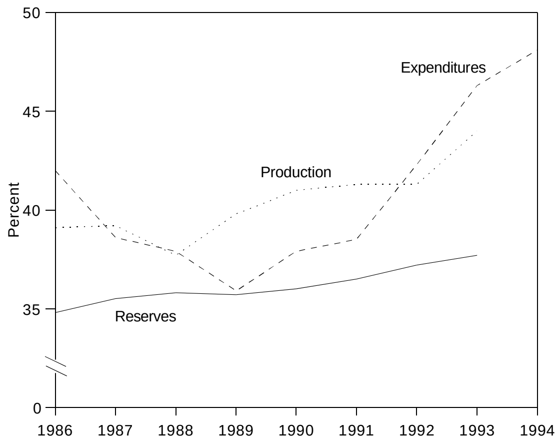
[3]Consistent with EIA conversion factors, dry natural gas production is converted to crude oil equivalent at the rate of 0.18 barrels per thousand cubic feet.

[4]See the box, "Defining the Majors, Nonmajors, and Independents," for an explanation of net ownership and producers other than the majors.

[5]The last estimates of total U.S. exploration and development expenditures based on an industrywide statistical survey was in 1991 and was reported in the American Petroleum Institute, *Survey of Oil and Gas Expenditures* (Washington, DC, November 1992). In this report, total U.S. exploration and development expenditures for 1992 were estimated by first computing the percent change in expenditures from 1991 to 1992 for companies other than the major energy companies reporting expenditures to EIA's Financial Reporting System (FRS) that reported expenditures for both 1991 and 1992 and were included in Arthur Andersen & Co., *Oil and Gas Reserve Disclosures* (Chicago, IL: July 1994): This percent change from 1991-1992 was applied to the total 1991 U.S. expenditures (reported by the American Petroleum Institute) less the total for FRS companies to obtain an estimate for the independent non-FRS oil and gas producers' U.S. expenditures in 1992. This estimate, plus the actual reported 1992 expenditures of the FRS companies, yields the estimate of total U.S. expenditures for 1992. For the 1993 estimate, a similar procedure based on companies reporting expenditures in both 1992 and 1993 was applied to the 1992 estimate. For 1994 and 1995, the estimate was based on companies included in both the Arthur Andersen & Co. publication and Salomon Brothers, Inc., *Survey and Analysis of 1995 Worldwide Oil and Gas Exploration and Production Expenditures* (January 3, 1995). It should be noted that expenditures, and expenditure estimates, exclude expenditures for proved acreage.

[6]See, for example, Energy Information Administration, *Performance Profiles of Major Energy Producers 1986*, DOE/EIA-0206 (86) (Washington, DC, January 1986), Table 38.

Figure 1. Percent of U.S. Oil and Gas Production, Reserves, and Exploration and Development Expenditures for Nonmajor Oil and Gas Producers



Note: Due to year-to-year volatility, expenditures are shown as a three-year moving average. Nonmajors = Total (less 15 percent for royalties) minus majors.

Source: **Reserves and production:** U.S. Total: Energy Information Administration, *U.S. Crude Oil, Natural Gas, Natural Gas Liquids Reserves*, DOE/EIA-0216(93) (Washington, DC, October 1994). Majors: Energy Information Administration, Form EIA-28. **Expenditures:** Energy Information Administration, *U.S. Energy Industry Financial Developments, 1995 First Quarter*, DOE/EIA-0543 (95/1Q) (Washington, DC, June 1995).

development strategies in U.S. oil and gas increasingly reflects the decisions of smaller, typically more specialized producers, what consequences can be seen regarding the costs of adding to U.S. reserves? How are capital markets accessed? Are U.S. oil and gas investments by the nonmajors likely to be undertaken only with higher costs of capital? The remainder of this report analyzes these issues.

Defining the Majors, Nonmajors, and Independents

The Energy Information Administration (EIA) collects annual financial and operating information from companies that are determined to be major energy producers. In 1993, the latest year of data availability, 25 companies (the “majors”) reported on Form EIA-28 (Financial Reporting System (FRS)).[a] Information is reported on a net ownership basis. Net ownership includes all of a company’s fractional ownership shares in oil and gas properties but excludes royalty interests.

EIA also collects annual data on U.S. reserves of oil (crude oil and natural gas liquids) and natural gas, changes in reserves, and production from reserves.[b] These data are collected on an operator basis, rather than an ownership basis, and include royalty interests. However, reserves and production on a net ownership basis for companies other than the majors can be estimated. Royalty interests are about 15 percent of U.S. oil and gas production. Aggregate estimates of reserves, production, and changes in reserves for companies other than the majors (“nonmajors”) can be obtained by subtracting the FRS totals from the U.S. totals, excluding royalty interests. In Chapters 1 and 2, this aggregate of net ownership interest other than the majors will be termed “nonmajors.” This dichotomy will prove useful in understanding the structure and performance of the U.S. oil and gas industry.

Most of the nonmajors are specialized oil and gas producers, often referred to as “independents.” However, other types of companies, such as pipeline and refinery operators, account for a significant share of U.S. oil and gas production and reserves. Since the distinctions among the nonmajors will help in understanding the structure and performance of the U.S. oil and gas industry, differences among these company groups will be addressed in Chapters 3 through 5.[c]

[a]A list of the companies included in the FRS and the criteria for respondent selection are in the Appendix.

[b]These data are presented annually in Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216 (Washington, DC).

[c]A small number of foreign subsidiaries are included in other operations.

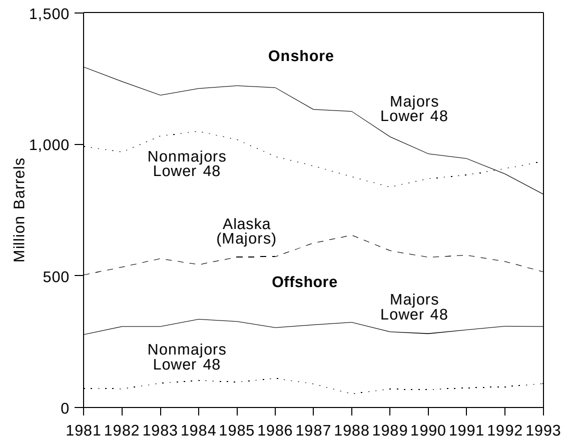
2. Sources of Increased Production

The share of the nonmajors' combined U.S. oil and gas production has shown a fairly steady increase since 1989 (Figure 1). However, patterns over time differ considerably between oil and gas and between onshore and offshore locales. Accordingly, the review in this chapter is separated by energy source and locale.

Oil Production

Growth in the nonmajors' oil production in the 1990's was largely derived from the lower 48 onshore (Figure 2).[7] This growth in the 1990's marks a change from sharp cutbacks in production by the majors and nonmajors following the oil price collapse of late 1985 and early 1986. The nonmajors cut their lower 48 onshore oil production by nearly 500,000 barrels per day between 1985 and 1989 (an 18-percent decline) while the majors made even larger reductions. After 1989, the nonmajors reversed the earlier trend in oil production and, by 1993, about matched their 1986 production. However, the majors' lower 48 onshore oil production continued to decline through the early 1990's.

Figure 2. U.S. Oil Production by Region for Majors and Nonmajors



Note: Data are on a net ownership basis and exclude estimated royalties of 15 percent. Nonmajors = U.S. totals minus majors.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **U.S. Totals:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* DOE/EIA-0216(93) (Washington, DC, October 1994).

Drilling Adds More Reserves than Purchases

What were the sources of growth in the nonmajors' oil production? Within the context of accounting for energy reserves and production, there are three possibilities: purchases from the majors, exploration and development performance, or more rapid extraction of oil reserves.

Production may have grown through purchases of reserves from the majors. Net purchases of oil reserves from the majors (i.e., from the FRS group to nonmajors in total) totaled nearly 500 million barrels over the 1989-1993 period. However, net purchases accounted for only 14 percent of the nonmajors' total U.S. oil reserve additions in the lower 48 onshore (Table 1).

Reserves added through drilling may have outpaced production. Nonmajors added 2.9 billion barrels of oil to their lower 48 onshore reserves through extensions, discoveries, improved recovery, and revisions of earlier

[7] Reserves and production data for the majors (i.e., the FRS companies) are collected, through Form EIA-28, separately for onshore (which includes Alaska) and offshore (which includes the Federal Outer Continental Shelf and State offshore). State-by-State reserves and production data, including separate reporting of Federal Outer Continental Shelf and State offshore data, are available from the Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves.* The task of deriving estimates of the majors' lower 48 onshore production and reserves is made easy by the fact that ownership (excluding royalty interests) of virtually all of the reserves and production in Alaska is attributable to the FRS companies. Thus, lower 48 onshore data for the majors is estimated as the difference between values reported as onshore on Form EIA-28 minus corresponding values (less 15 percent for royalty interest) for Alaska in the reserves report.

Table 1. Lower 48 Onshore Oil Reserves and Production for Nonmajors, 1989-1993

	Million Barrels
Beginning-of-1989 Reserves	8,914
+ Reserve Additions, 1989-1993	2,937
+ Net Purchases from Majors, 1989-1993	486
- Production, 1989-1993	-4,435
= End-of-1993 Reserves	7,902
Replacement Rate, 1989-1993 (percent)	
Excluding Net Purchases	66
Including Net Purchases	77

Note: Replacement rate = Reserve additions/production. Nonmajors = Total United States (less 15 percent royalty interest) minus majors.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1989-1993 issues, DOE/EIA-0216 (Washington, DC).

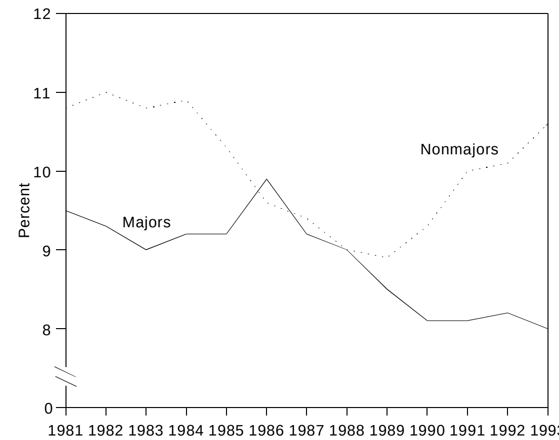
estimates over the 1989-1993 period. Even including net purchases, growth in the nonmajors' reserve base was insufficient to replace production. If growth in the reserve base did not offset the growth in production, then only one other source of increased production is apparent.

Growth Through More Rapid Depletion

An increased rate of extraction may have added to production. The rate of extraction is the proportion of reserves going to production. The annual rate of extraction[8] of lower 48 onshore oil reserves by the nonmajors steadily increased, from 8.9 percent in 1989 to 10.6 percent in 1993 (Figure 3). In contrast, the comparable extraction rate for the majors varied within a narrow 8.0-percent to 8.5-percent range over the same period.

The nonmajors' increased extraction rate was probably a phase of their adjustment to lower oil prices. During the U.S. drilling boom of the late 1970's and early 1980's, oil and gas reserves were added which not only

Figure 3. Extraction Rates for Lower 48 Onshore Oil Reserves



Note: Extraction Rate = Production/(End-of-year reserves + production). Nonmajors = Total United States (less 15 percent royalty interest) minus majors.

Sources: **Majors**: Energy Information Administration, Form EIA-28; **Total United States**: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1981-1993 issues, DOE/EIA-0216 (Washington, DC).

were costly to discover and develop but also entailed high costs of production (lifting costs). High oil prices and the expectation of rising oil prices in the future justified adding high-cost reserves to producers' books. The downside of this high-cost strategy became painfully evident when oil prices began to decline modestly at first in the early 1980's and then crashed in late 1985 and early 1986. Oil producers responded by cutting back on higher cost production, but, as long as asset values were properly adjusted,[9] there was no imperative to remove reserves from their books unless the associated field was fully abandoned. Consequently, the decline in the computed extraction rate from 1985 to 1989 may largely have reflected the combination of production cutbacks and a reluctance to remove reserves from the books.

After low oil prices were recognized as the norm, high-cost reserves were removed from companies' books altogether. However, by the late 1980's, prices of

[8]Extraction rate = annual production/(end-of-year reserves + annual production).

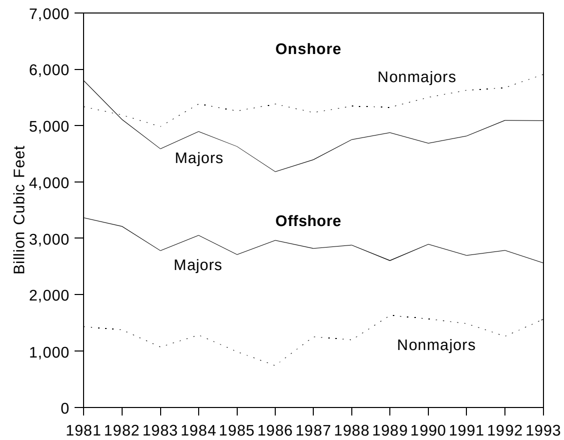
[9]For companies using the full-cost method of accounting, the net value of oil and gas properties carried on the balance sheet should not exceed the present value (discount of 10 percent) of future cash flows from proved reserves. If the balance sheet value exceeds the net present value, then the balance sheet value must be reduced by the excess value. However, this accounting rule does not require any removal of oil and gas reserves from a company's books. For a detailed explanation, see Sidney Davidson and Roman L. Weil, *Handbook of Modern Accounting,* Third Edition (Colorado Springs, CO: Shepards/McGraw-Hill, 1983), Chapter 18, especially pp. 18-14 and 18-15.

drilling and production services had declined in response to lower oil prices, making some fields again economic. Also, given lower oil prices, new production was likely to be derived from low-cost reserves. Consequently, the rise in extraction rates in the 1990's reflected the combination of removing high-cost reserves from the books and increased production—in part, from new low-cost fields and, in part, from formerly subeconomic fields. Nevertheless, nonmajors' extraction rates from lower 48 oil reserves have not yet quite matched the extraction rates of the early 1980's.

In the context of reserve accounting, the increase in the nonmajors' lower 48 onshore oil production between 1989 and 1993 breaks down as follows: reserves added through drilling, 57 percent; increased extraction rate, 33 percent; and net purchases of reserves, 10 percent.[10]

Offshore locales[11] contributed little to the growth in the nonmajors' share of U.S. oil production. For both majors and other producers, there was little overall change in offshore oil production in the late 1980's and thus far in the 1990's (Figure 2). Instead, the nonmajors directed offshore operations toward producing natural gas.

Figure 4. U.S. Natural Gas Production for Majors and Nonmajors



Note: Data are on a net ownership basis and exclude estimated royalties of 15 percent. Nonmajors = U.S. totals minus majors.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **U.S. Totals:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* DOE/EIA-0216(93) (Washington, DC, October 1994).

Natural Gas Production

Offshore locales, mostly in the Gulf of Mexico, have been the most important source of gains by the nonmajors in U.S. natural gas production. Onshore, growth in the majors' natural gas production outpaced that of other producers (Figure 4), reducing the nonmajors' share of Lower 48 onshore natural gas production from 56 percent in 1986 to 54 percent in 1993. By contrast, the nonmajors' offshore natural gas production more than doubled between 1986 and 1993, with their associated share rising from 20 percent to 38 percent.

Two distinct phases in the nonmajors' offshore ascendence are evident (Figure 4). Between 1986 and 1989, their offshore natural gas production increased 120 percent, but, during the 1990's, production fell slightly. Exploration and development strategies and performance differed markedly between the two periods.

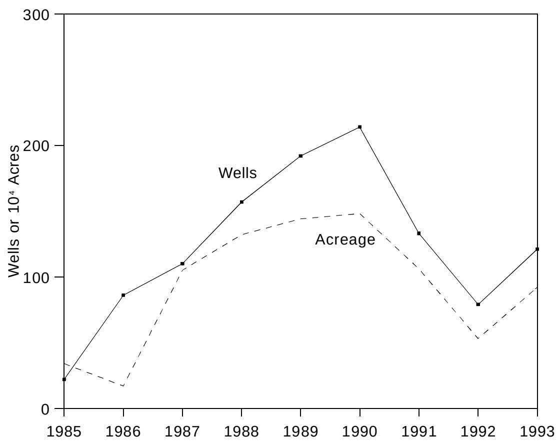
Large Offshore Gains in the 1980's

Offshore drilling activity by the nonmajors nearly tripled in the late 1980's, with drilling for natural gas accounting for most of the growth (Figure 5). Over the

[10]This calculation was made using successively applied sets of assumptions. The first set of assumptions was that no reserves were added or purchased over the 1989-1993 period and remaining reserves were extracted at 1989's 8.9-percent rate for the entire period. Under these assumptions, implied production in 1993 would be 546 million barrels. Next, assume reserve additions (excluding purchases of proved reserves) over the 1989-1993 period were equal to their actual values, but reserves were extracted at 1989's 8.9 percent rate for the entire period. In this case, implied 1993 production would be 768 million barrels. Thus, an estimate of the increment in 1993 production due to actual reserve additions (excluding purchases of proved reserves) is 768 million barrels - 546 million barrels = 222 million barrels. Thirdly, assume reserve additions and net purchases of proved reserves were equal to their actual values over 1989-1993 and the extraction rate was assumed equal to 8.9 percent. In this case, implied 1993 production would be 807 million barrels and the increment attributable to purchases can be estimated as 807 million barrels - 768 million barrels = 39 million barrels. Finally, the increment in 1993 production attributable to increased extraction is 935 million barrels (actual 1993 production) - 807 million barrels = 128 million barrels. Thus, the sources of increased production are reserve additions, 57 percent (i.e., 222/(935-546)); net purchases, 10 percent; and increased extraction rate, 33 percent.

[11]Offshore includes the Federal Outer Continental Shelf and State offshore areas.

Figure 5. Offshore Development Gas Wells Completed and OCS Acreage Awarded for Nonmajors



Note: Nonmajors = Total United States minus majors.

Sources: **Wells completed:** Majors: Energy Information Administration, Form EIA-28; Total United States: Special compilation provided by the Office of Oil and Gas, Energy Information Administration, based on data which appeared in the *Monthly Energy Review*, September 1994, p. 83. **Acreage awarded:** Majors: Special compilation provided by the U.S. Department of the Interior, Minerals Management Service. Total United States: U.S. Department of the Interior, Minerals Management Service, *Federal Offshore Statistics: 1993* (Herndon, VA, 1994).

same span, Federal Outer Continental Shelf (OCS) acreage awarded to nonmajors registered substantial growth as well. Part of this surge in activity was attributable to the change in Federal OCS leasing policy. Area wide leasing, which was instituted by the U.S. Department of the Interior in the early 1980's, made much more acreage available. In 1983, for example, 120 million acres in the OCS were offered for bid compared with 8 million acres the year before.[12] In particular, the generally smaller, more proximate pools favored by the nonmajors were in abundance. Technological improvements also contributed to the growth in drilling activity. Some developments, such as three-dimensional seismic techniques, benefitted both the majors and other companies, while other developments, such as "off-the-shelf" platforms, were boons especially to the smaller companies.

The upswing in the nonmajors' offshore gas drilling activity in the late 1980's added considerably to their reserve base and production capability. Over the 1986-1989 period, the nonmajors more than replaced their production with reserve additions gained through drilling (Table 2). Purchases of offshore gas reserves from the majors, on balance, were practically nil over this period. Adding reserves at a pace that exceeded production was a key source of the nonmajors' heightened role in offshore gas production in the 1980's.

Table 2. Offshore Natural Gas Reserves and Production for Nonmajors, 1986-1989 and 1990-1993
(Billion Cubic Feet)

	1986-1989	**1990-1993**
Beginning Reserves	7,520	7,828
+ Reserve Additions	5,142	1,271
+ Net Purchases from Majors .	-16	1,604
- Production	-4,818	-5,875
= Ending Reserves	7,828	4,828
Replacement Rate (percent)		
Excluding Net Purchases	107	22
Including Net Purchases	106	49

Note: Replacement rate = Reserve additions/production. Nonmajors = Total United States (less 15 percent royalty interest) minus majors.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1989-1993 issues, DOE/EIA-0216 (Washington, DC).

Offshore Gains Wiped Out in the 1990's, Smaller Fields Predominate

The 1990's present a much different picture. Offshore gas reserves added by the nonmajors through drilling replaced only 22 percent of their production over the 1990-1993 period. Reserve additions were only a quarter of the level achieved in the prior 4 years. The sharp falloff in reserve additions reflected the plunge in the nonmajors' offshore drilling activity, led by cutbacks in gas well completions (Figure 5). However, reserve purchases from the majors became an important source

[12]U.S. Department of the Interior, Minerals Management Service, *Federal Offshore Statistics: 1993*, MMS 94-0060 (Herndon, VA, 1994), Table 3.

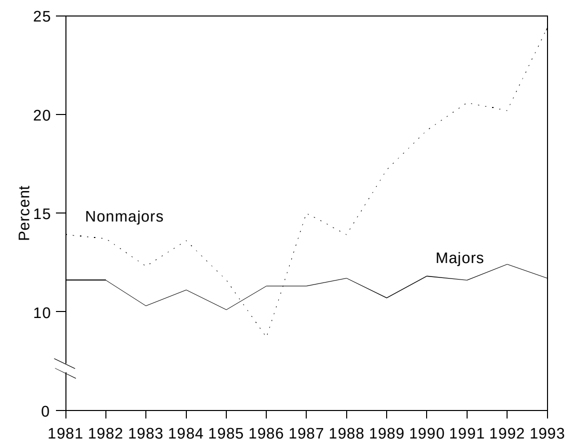
of added production in the 1990's, and exceeded reserve additions gained through drilling by a considerable margin. Nevertheless, even with this increase in reserve purchases, the nonmajors replaced only 49 percent of their offshore gas production in the 1990-1993 period.

With this sort of performance, and with reserves falling by nearly 40 percent, how did the nonmajors maintain only a slightly diminished level of offshore gas production in the 1990's (Figure 4)? Again, reserve accounting reveals a rise in the rate at which offshore gas reserves were drawn down (Figure 6). In contrast, the majors' extraction rate was up less than half a percentage point between 1986 and 1993. Unlike the rise in the nonmajors' extraction rate for lower 48 onshore oil reserves, which was mainly interpreted as a return to pre-oil price collapse rates of extraction, the sharp upswing in offshore gas extraction rates probably reflects smaller field sizes.

Generally, smaller oil and gas deposits entail higher production costs. Among the majors, a one-percent reduction in field size corresponds to a 0.18-percent increase in direct lifting costs.[13] [14] With higher (per-unit) production costs, more rapid rates of extraction are usually required in order for smaller fields to be economic.

Rising rates of extraction probably reflect, in part, smaller offshore gas fields for the nonmajors. Average discovery size offshore for the nonmajors fell from 1.3 million barrels (COE) per well completed, in 1988-1990, to 1.1 million barrels in 1991-1993, a 21-percent decline.[15] In contrast, the majors' average offshore discovery increased from 1.5 million barrels to 2.0 million barrels over the same period.

Figure 6. Extraction Rates for Offshore Natural Gas Reserves



Note: Extraction Rate = Production/(End-of-year reserves + production). Nonmajors = Total United States (less 15 percent royalty interest) minus majors.

Sources: **Majors**: Energy Information Administration, Form EIA-28. **Total United States**: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* 1981-1993 issues, DOE/EIA-0216 (Washington, DC).

Area wide leasing has caused marked changes in the nonmajors' involvement in offshore activity. In 1983, the first year of area wide leasing, about 30 nonmajors were producing from the Federal OCS. By 1993, nearly 100 nonmajors were OCS producers.[16] Field sizes changed dramatically, as well. Offshore reserves added per well in 1980-1982, prior to area wide leasing, for nonmajors averaged 3.9 million barrels, compared with 1.1 million barrels in 1991-1993. The majors, by contrast,

[13]Direct lifting costs are the costs associated with the extraction of oil and/or natural gas from a producing property, excluding production and property taxes. Field size is measured by annual oil and gas production (barrels of crude oil equivalent) per producing well.

[14]The negative (logarithmic) relationship between direct lifting costs (per unit of offshore production) and field size (t-ratios in parentheses) was estimated utilizing the FRS data:

$$\log(\text{Direct lifting costs}) = \underset{(15.88)}{2.73} - \underset{(4.15)}{0.18}\log(\text{Field size})$$
$$n = 769,\ \text{adjusted } R^2 = 0.24.$$

The 769 annual observations are for onshore and offshore separately, by company, for the years 1977-1993. Dollars were adjusted for inflation using the implicit Gross Domestic Product deflator (in 1993 dollars). The coefficient on a dummy variable for offshore observations was not significant. Inclusion of a dummy variable for each year did significantly reduce the residual variance.

[15]Average discovery size = Reserves added / wells completed, three-year weighted average.

[16] U.S. Department of the Interior, Minerals Management Service, *Federal Offshore Statistics: 1993,* MMS 94-0060 (Herndon, VA, 1994) p. 98.

appeared to go further offshore seeking ever larger fields: their average offshore discovery size more than doubled over the same period.

Statements made by the president of a nonmajor company "... that has as its primary objective developing already discovered [offshore] reserves that were uneconomic to previous operators..." are also instructive:[17]

> ...Control over timing is the most important factor. We can push development at every stage and get a quick pay out, and this is vital to smaller independents. ... We force projects through very small hoops. They have to pay for themselves very quickly.

[17]"Independents Stake Claim on Rich Gulf Reserves," *The American Oil and Gas Reporter,* April 1995, pp. 86, 88.

3. Composition of Oil and Gas Producers

In the previous chapter, companies were only distinguished by whether or not they could be classified as major petroleum companies. This gross dichotomy was necessary in order to review the overall role of nonmajor U.S. oil and gas producers in the context of the entire industry. However, far from being a homogeneous group, the nonmajors are diverse in a number characteristics such as degree of specialization and corporate structure. Specialized companies, generally termed the "independents," were mainly responsible for the nonmajors' growth in oil and gas production, as reported in the previous chapter.

Size and Numbers

Most Producers Are Small and Private

Most oil and gas producers are privately owned companies, which tend to be much smaller than publicly traded oil and gas producers. For example, in 1992, when the majors produced a per company average of 345,000 barrels per day (COE), the other publicly-traded oil and gas companies included in this report produced an average of 10,000 barrels per day, and the remaining oil and gas companies produced an average of only 300 barrels per day.[18] These small private producers are quite numerous, accounting for about 7,400 of the nearly 8,000 companies reporting oil and/or natural gas production in the United States in 1992.[19] In the same year, 427 publicly traded corporations disclosed that Standard Industrial Code (SIC) 1311 (oil and gas extraction) was one of the industries in which they operate, of which 327 stated that SIC 1311 was their primary industry.[20]

The publicly traded producers annually disclose their oil and gas reserves, production, and exploration and development expenditures. The firm of Arthur Andersen and Company has compiled these disclosures for the 1981-1993 period. These compilations, together with other corporate financial disclosures, will be utilized throughout the remainder of this report. Since oil and gas producers are subject to the same market forces, regardless of ownership structure, it is reasonable to expect that findings based on data for publicly traded independent producers apply to the privately owned independent producers as well.

Companies in the Arthur Andersen and Company database were classified (for purposes of this report) as follows, based on the companies' disclosures of their primary and secondary SIC codes: "independent producers" (primary industry code SIC 13) and "other producers" (primary SIC other than SIC 13, but reporting oil and/or gas production). Other publicly traded oil and gas producers were further subdivided (based on primary SIC's) into refiners, pipelines/utilities, Canadian or other foreign-based, or diversified companies.

Independents Increase Production Share

Among U.S. oil and gas producers, the independents have gained an increased role in the industry following the oil price collapse. The publicly traded independents' share of U.S. oil and gas production, on a net ownership basis, increased from 7 percent in 1985 to 8 percent in 1993 while the privately owned producers' share increased from 26 percent to 31 percent (Table 3). The majors' share fell from 61 percent to 56 percent. The

[18]For these averages, the data for the majors were taken from Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994). The data for other publicly traded oil and gas companies were compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database*, 1989-1993 (Chicago, IL, 1994); the U.S. totals for production and number of companies came from U.S. Department of Commerce, Bureau of the Census, *1992 Census of Mineral Industries, Industry Series, Crude Petroleum and Natural Gas* (July 1995). Remaining oil and gas companies = U.S. total - majors - other publicly traded oil and gas companies.

[19]U.S. Department of Commerce, Bureau of the Census, *1992 Census of Mineral Industries, Industry Series, Crude Petroleum and Natural Gas* (July 1995).

[20]Based on company filings of Security and Exchange Commission Form 10K as compiled by Disclosure, Inc.

Table 3. Percent Distribution of U.S. Oil and Gas Production for Majors, Independents, and Other Producers, 1985 and 1993

	Percent Share of U.S. Oil and Gas Production (Crude Oil Equivalent)	
	1985	1993
Majors	60.6	56.0
Publicly-traded Companies		
Independents	7.0	8.2
Other Producers	6.4	5.2
Private Companies	26.0	30.7
Total[a]	100.0	100.0

[a]Assumes a 15 percent royalty on production.

Note: Private companies = U.S. Total minus majors minus publicly traded companies.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **Publicly traded companies:** Arthur Andersen & Co., *Oil and Gas Reserve Disclosures,* 1981-1985, and Fifteenth Edition 1994 (Chicago, IL, 1986 and 1994); **Total United States:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves,* DOE/EIA-0216 (Washington, DC, October 1994).

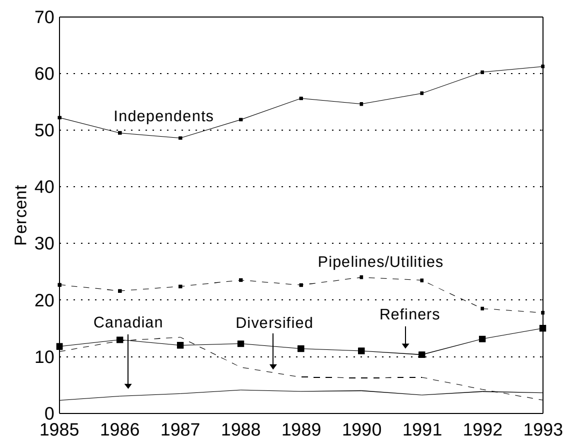
share for other publicly traded producers decreased from 6 percent to 5 percent.

Apart from the majors, diversified companies showed the most retrenchment in U.S. oil and gas production following the oil price collapse (Table 3 and Figure 7). Pipelines and utilities also reduced their commitment to upstream production. Overall, refiners and Canadian-based producers showed little change in their role in U.S. oil and gas production.

Entry and Exit

Although entry and exit into the ranks of the majors are infrequent, the rest of the U.S. oil and gas industry has experienced considerable comings and goings of companies. The Arthur Andersen and Company database was reviewed and the independents were classified as survivors (independents that were in production in 1985 and 1993), nonsurvivors (companies that were not in production in 1993), and entrants (companies that were in production in 1993 but not in 1985). For the independents overall, total assets declined by about a third between the end of 1985 and the end of 1993 (Figure 8). All of this decline was attributable to exiting companies. Excluding these nonsurvivors, total assets of the independents grew by about a third. Entrant companies accounted for most of the growth. Independents that survived the period as

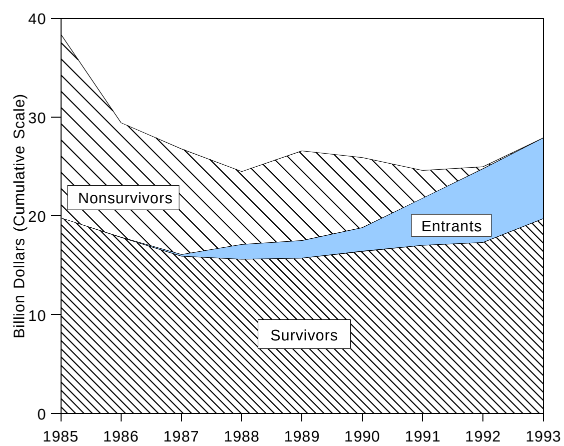
Figure 7. Composition of Publicly Traded Nonmajor Companies' U.S. Oil and Gas Production



Note: Companies are classified on the basis of their primary Standard Industrial Codes.

Source: Compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database,* 1984-1988 and 1989-1993 (Chicago, IL, 1989 and 1994).

Figure 8. Total Assets of Publicly Traded Independent Oil and Gas Producers



Note: Companies' primary industry is Standard Industrial Code 13.

Source: Compustat, a service of Standard & Poor's.

intact corporate entities and are still producing oil and gas showed a modest decline in total assets during the 1980's but have clearly registered some growth in assets in the 1990's.

The U.S. oil and gas industry exhibited considerable dynamism following the oil price collapse. In order to better understand the current and future development of the industry, it is worth inquiring as to what factors contributed to the patterns of growth, decline, and exit following the oil price collapse.

The sources of growth and decline in U.S. oil and gas production are rooted in companies' ability to add efficiently to their reserves. This report turns next to a review of resource development costs. The analysis is directed to the relationships between resource development costs and changes in industry structure and some of the consequences of these relationships for future development of the U.S. oil and gas industry.

4. Resource Development Costs

Replacing reserves used up in production is a fundamental requirement of survival in the oil and gas industry. In a low oil price environment, as has been the situation since 1986, adding reserves at a low cost becomes imperative. The first part of this chapter examines reserve replacement costs for surviving and nonsurviving independent oil and gas producers in order to evaluate the effect of these costs on product markets' and capital markets' sorting of winners and losers in the oil and gas industry. The second part of this chapter compares the costs of adding to U.S. oil and gas reserves of the majors and the surviving independents. The resource development strategies of these two groups have been shown to be markedly different.[21] Consequently, their respective costs of adding reserves might differ. If the independents continue to expand their role in U.S. oil and gas development, then cost differences will tend to be amplified in the future.

Resource Development Costs: The Company Perspective

A company can replace its oil and gas reserves by successful exploration and drilling, whereby formerly untapped deposits are added to productive capacity, or by outright purchase of proven reserves from another reserve owner. Since either method can be employed, measuring the costs *to the company* should account for both. One such measure that has been employed frequently within the oil and gas industry[22] is termed reserve replacement costs. For a company, reserve replacement costs are measured by the ratio of expenditures (for unproved lease acquisitions, acquisition of proven reserves, exploration, and development) to barrels of oil and gas reserves (on a COE basis) added to the company's books (through extensions, discoveries, improved recovery, revisions of previous estimates, and purchase of proven reserves from other companies).

Since there can be lags between expenditures and associated reserve additions, reserve replacement costs are measured as three-year weighted averages. Reserve replacement costs are measured before tax effects. The overall effect of taxes on reserve replacement costs has been found to differ little between majors and nonmajors.[23] For the purposes of comparison, reserve replacement costs are computed for four categories of U.S. oil and gas producers: the majors (represented by the FRS companies), surviving independents (i.e., specialized companies that produced oil and / or gas in 1993), nonsurviving independents (i.e., specialized companies that produced U.S. oil and / or gas sometime prior to 1993 but did not exist in 1993), and other producers (refiners, pipelines, utilities, Canadian-based companies, and diversified companies).

In the 1990's, U.S. reserve replacement costs of the majors and surviving independents were nearly equal at about $5 per barrel of added reserves (in 1993 dollars) (Figure 9). Even in the late 1980's, reserve replacement costs of the two groups differed by only a few cents per barrel. Reserve replacement costs for independents that exited the industry were slightly higher at about the time of the oil price collapse. Thereafter, the costs for nonsurviving independents compared to surviving independents continued to grow, and by 1990-1992 were nearly $4 per barrel higher. Other producers (such as diversified companies) also incurred higher reserve replacement costs.

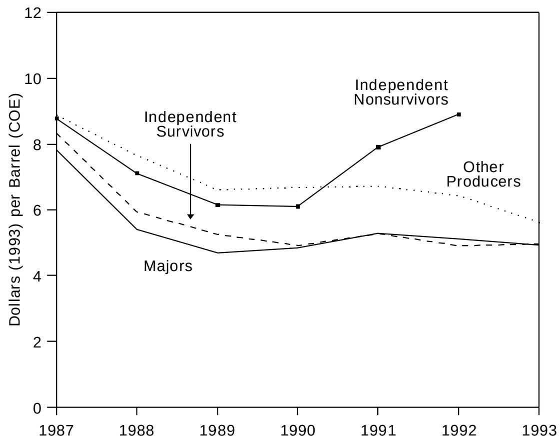
These results reinforce the view that the market forces to which U.S. oil and gas producers have been subject forced efficiency in resource development. That is, as the industry adjusted to the lower level of prices

[21]See Energy Information Administration, *Performance Profiles of Major Energy Producers 1986*, DOE / EIA-0206(86) (Washington, DC, January 1986), Table 38.

[22]See Arthur Andersen & Co., *Oil & Gas Reserve Disclosures* (Chicago, IL, 1994), pp.11-12, and "Pros, Cons of Techniques Used to Calculate Oil, Gas Finding Costs," *Oil and Gas Journal*, June 1, 1992, pp. 93-95.

[23]Energy Information Administration, *Performance Profiles of Major Energy Producers 1987*, DOE / EIA-0206(87) (Washington, DC, January 1989), pp. 62-65. The calculations in this source assumed no benefits from percentage depletion.

Figure 9. U.S. Reserve Replacement Costs for Majors and Publicly Traded Oil and Gas Producers



COE = Crude oil equivalent.

Note: Reserve replacement costs = Exploration and development expenditures (including acquisitions of unproved and proved acreage)/reserves added (including purchases of proved reserves), three-year weighted average. Independent oil and gas producers' primary industry is Standard Industrial Code 13.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **Publicly traded companies:** compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database*, 1984-1988 and 1989-1993 (Chicago, 1989 and 1994).

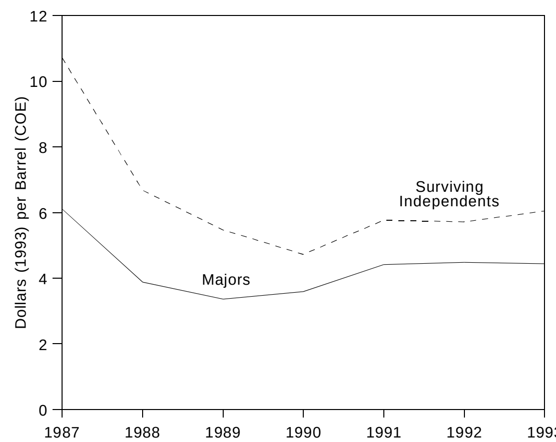
following the oil price collapse of the mid-1980's, the companies that competed successfully tended to incur lower costs of adding to their reserve bases than those companies that reduced or withdrew their asset commitments to U.S. oil and gas production.

Resource Development Costs: An Economywide Perspective

Reserve replacement costs measure the cost *to the company* of adding to their reserve base, whether through the company's own exploration and development efforts or through outright purchase of proven reserves from another company. For the economy as a whole, though, reserve replacement costs may not be the most appropriate measure of the actual costs of adding to U.S. oil and gas reserves. Reserve replacement costs include expenditures for acquisitions of proven reserves as well as acquisitions of leases for unproven acreage. However, for the economy as a whole, acquisitions represent only a transfer of ownership. Net additions to U.S. reserves from acquisitions are always zero. In order to ascertain if the structural changes in the U.S. oil and gas industry might affect the costs of adding to reserves for the economy as a whole, a different measure is needed.

Excluding expenditures for acreage acquisitions, whether proven or unproven, and excluding existing reserves gained through purchases will more accurately reflect the economywide costs of adding to U.S. oil and gas reserves. Thus, the ratio of exploration and development expenditures (excluding acquisitions of leases and proven acreage) to reserve additions (excluding purchases of proven reserves) will be used as the economywide cost measure, and will be termed, "overall finding costs."[24] Figure 10 presents overall U.S. finding costs for two groups: Majors and surviving independents.

Figure 10. Overall Finding Costs for Majors and Publicly Traded Surviving Independents



COE = Crude oil equivalent.

Note: Overall finding costs = exploration and development expenditures (excluding acquisitions of unproved and proved acreage)/reserves added (excluding purchases of proved reserves), three-year weighted average. Independent oil and gas producers' primary industry is Standard Industrial Code 13.

Sources: **Majors:** Energy Information Administration, Form EIA-28; **Publicly traded companies:** compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database*, 1984-1988 and 1989-1993 (Chicago, 1989 and 1994).

[24]For an extensive review of alternative measures of the cost of adding oil and gas reserves, see "Pros, Cons of Techniques Used to Calculate Oil, Gas Finding Costs," *Oil and Gas Journal*, June 1, 1992, pp. 93-95.

Overall U.S. finding costs for surviving independents are clearly higher than the majors' overall U.S. finding costs. Most recently (1991-1993), surviving independents' costs were nearly $2 per barrel of added reserves (in 1993 dollars) more than the majors. In the mid-1980's, the difference was about $5 per barrel, so the gap has narrowed but not disappeared.[25]

This latter result should be interpreted very carefully. Beginning in the early 1980's, the costs of finding oil and gas have declined in the United States.[26] Technological change and market adjustments have over time reduced the costs of adding reserves. However, at any point in time, finding more oil and gas will typically entail ever higher costs. That is, finding oil and gas reserves is subject to diminishing returns. Consequently, there is a tendency for companies that are expanding their reserves base to have higher finding costs than companies that are contracting.

In the 1990's, the surviving independents, overall, have been increasing their investments in U.S. exploration and development. In contrast, the majors, overall, sharply reduced their U.S. exploration and development commitments until the early 1990's from which time they have leveled off. The higher overall finding costs of the surviving independents compared with the majors, in part, reflects both an expansion of the independents' U.S. oil and gas operations and a consolidation of the majors' operations.

[25]The difference of $2 per barrel for overall finding costs between the independents and majors and virtually no difference for reserve replacement costs suggest that the independents paid less for their purchases of proven reserves than did the majors. However, this was not the case. The cost per COE barrel of purchased reserves for the majors (in 1993 dollars) was $2.64 (based on FRS data) but $3.59 for the surviving independents (based on the Arthur Andersen and Company data base) in 1991-1993. The seeming anomaly is explained by differences in the relative importance of reserve additions gained through drilling versus purchases. For the majors, 88 percent of total reserve additions came through drilling with 12 percent gained through purchases. For the independents, 37 percent of total reserve additions were attributable to drilling but 63 percent were obtained through purchases.

[26] Energy Information Administration, *Performance Profiles of Major Energy Producers 1993*, DOE/EIA-0206(93) (Washington, DC, January 1995), pp. 79-83.

5. Financial Performance of the Independent Oil and Gas Producers

A company's standing in the capital markets is reflected in the markets' evaluation of the company and investor willingness to provide funds to it. Investor perceptions are, in turn, influenced by financial results. For the independents, the oil price collapse of 1986 was the defining event in shaping financial factors such as cash flow, profitability, and cost. Independents that were able to survive the oil price collapse might be expected to have distinguishing characteristics which may have been discerned by investors.[27]

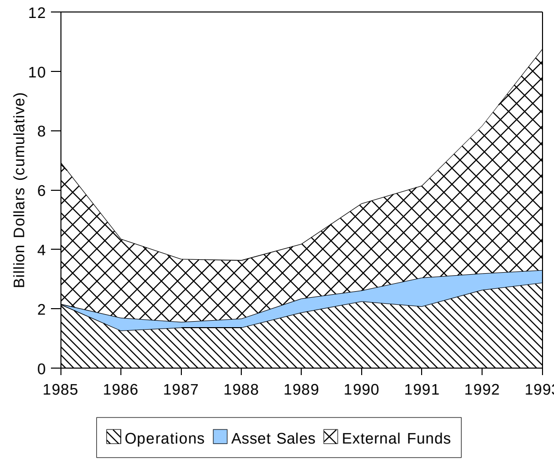
Financial Performance

Independents Rely Heavily on External Funds

The surviving independent oil and gas producers rely on external funds (from issues of long-term debt and equity securities, and change in current debt) more than on cash generated by operations (Figure 11). In contrast, the major petroleum companies use cash flow from operations as the predominant source of funds (Table 4). The main source of external funds for both the majors and the surviving independents has been long-term debt (Table 4). The majors currently rely on long-term debt for 27 percent of their funds, while the surviving independents rely on long-term debt for 49 percent of their funds.

Although they are more debt-dependent than the majors, the independents have been conscientious about reducing their dependence on debt. A highly leveraged firm (a firm with more debt than its peers) usually finds itself with higher fixed charges in the form of interest payments relative to discretionary outlays such as dividend payments. Faced with a crisis such as the oil price collapse, it would be less likely that a highly leveraged firm would be able to cover its interest payments with its operating cash flow, and may default on debt. The prospect of default and bankruptcy can be

Figure 11. Sources of Cash for Surviving Publicly Traded Independents



Note: External funds are the sum of proceeds from long-term debt, equity security offerings, and net changes in current debt.
Source: Compustat, a service of Standard and Poor's.

assumed to have a negative effect on investors, and the hope of reassuring investors may have motivated the independent oil producers to reduce debt. Since 1986, the surviving independents have allocated about 44 percent per year of their cash for debt reduction, while the majors have allocated about 27 percent of funds to reduce debt (Table 4). This allocation of funds has resulted in a dramatic decrease in the ratio of debt to equity for the surviving independents from over 150 percent to just under 110 percent in 1993 (Figure 12). This is in contrast to the large industrial companies (as represented by the Standard and Poor's (S&P) 400 group of industrial firms), who have increased debt relative to equity markedly since the 1980's.

In addition to reduction of debt, the independents devoted the bulk of their cash to reinvestment in their own operations, about 52 percent of cash outlays from

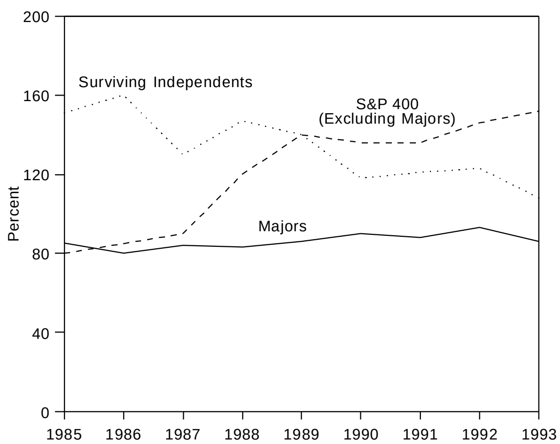
[27]The group of surviving independents includes entrants, defined as firms who entered the industry after 1985, and existed through 1993.

Table 4. Sources and Uses of Cash

	1986-1990	1991-1993	1986-1990	1991-1993
	billion dollars		percent distribution	
	Publicly Traded Independent Oil and Gas Producers			
Main Sources of Cash				
Cash Flow from Operations	8.0	7.5	36.8	30.4
Proceeds from Long-Term Debt	9.5	12.1	43.4	48.9
Proceeds from Disposal of Assets	1.8	1.9	8.1	7.9
Proceeds from Equity Security Offerings	2.6	3.2	11.7	12.8
Total	21.8	24.8	100.0	100.0
Main Uses of Cash				
Additions to Investment in Place	10.3	13.1	45.3	52.4
Reductions in Long-Term Debt	10.2	10.7	44.7	43.0
Dividends to Shareholders	1.4	0.9	6.3	3.5
Stock Repurchases	0.8	0.3	3.7	1.1
Total	22.7	24.9	100.0	100.0
Other Sources and Uses, Net	1.2	-0.2		
Net Change in Cash and Cash Equivalents	0.3	-0.2		
	Majors			
Main Sources of Cash				
Cash Flow from Operations	243.0	142.8	58.0	58.7
Proceeds from Long-Term Debt	105.9	65.8	25.3	27.1
Proceeds from Disposal of Assets	54.1	28.4	12.9	11.7
Proceeds from Equity Security Offerings	15.8	6.1	3.8	2.5
Total	418.8	243.1	100.0	100.0
Main Uses of Cash				
Additions to Investment in Place	214.6	128.7	51.1	54.3
Reductions in Long-Term Debt	116.1	64.6	27.6	27.2
Dividends to Shareholders	64.3	40.6	15.3	17.1
Stock Repurchases	24.9	3.3	5.9	1.4
Total	420.0	237.2	100.0	100.0
Other Sources and Uses, Net	-4.1	-7.4		
Net Change in Cash and Cash Equivalents	-5.3	-1.5		

Note: Totals may not equal sum of components due to independent rounding.
Sources: **Surviving Independents:** Compustat, a service of Standard and Poor's; **Majors:** Energy Information Administration, Form EIA-28.

Figure 12. Total Debt to Equity for Majors, Surviving Independent Oil and Gas Producers, and the S&P 400



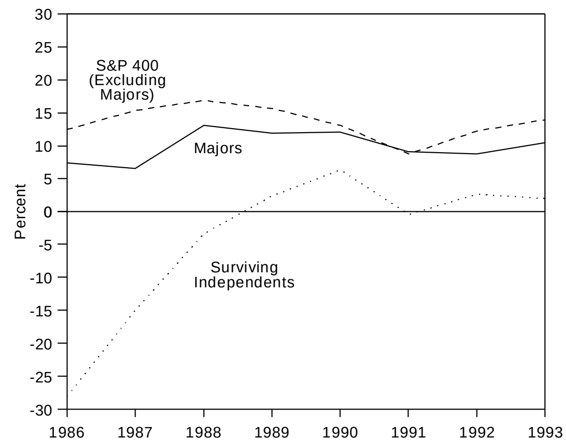
Source: **Majors:** Energy Information Administration, Form EIA-28; **S&P 400 and Surviving Independents:** Compustat, a service of Standard & Poor's.

1991 through 1993 (Table 4). The increases in debt reduction and reinvestment came at the expense of stockholder payout. Cash dividends paid to stockholders fell from 6 percent of cash outlays in 1986 through 1990 to only 4 percent of cash outlays in 1991 through 1993.

Profitability

Expected profitability is an important determinant of investors' perceptions of a company. Past profitability is usually regarded as a useful indicator of future profitability, and can be a guide to comparing companies' financial performance. An often-used measure of company profitability is net income as a percent of stockholders' equity, referred to as return on equity. The major oil companies typically engage in oil and gas production ("upstream" operations) and in refining and marketing ("downstream" operations). Poor profitability in the majors' upstream operations in low-oil-price years can sometimes be offset by better performance in downstream operations. Lacking this integration, the independents were devastated by the oil price collapse, earning a negative rate of return on investment for the years immediately following the price collapse (Figure 13).

Figure 13. Return on Equity for Petroleum Companies and U.S. Industry

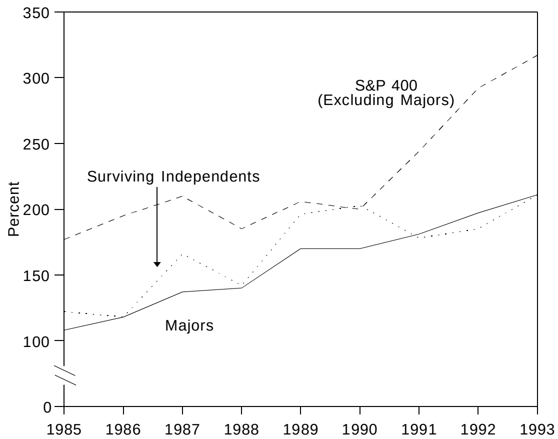


Source: Compustat, a service of Standard & Poor's.

The independents that survived the oil price collapse managed to improve profitability through the remainder of the 1980's (Figure 13). One indicator of investors' evaluation of this improved performance is the ratio of market value of the companies' shares to book value of the companies' net assets (i.e., stockholders' equity). A company's current share price reflects investors' expectations of profitability at the time the shares are purchased; book value reflects the future expected profitability of productive assets at the time the assets were purchased. The steadily increasing ratio of market value to book value for the independents reflected investor expectations of continued improvement in profitability (Figure 14). However, investors are more optimistic about the future of companies outside of oil and gas production, as evidenced by the much greater growth in the ratio of market value to book value for the S&P 400 group during the 1990's (Figure 14).

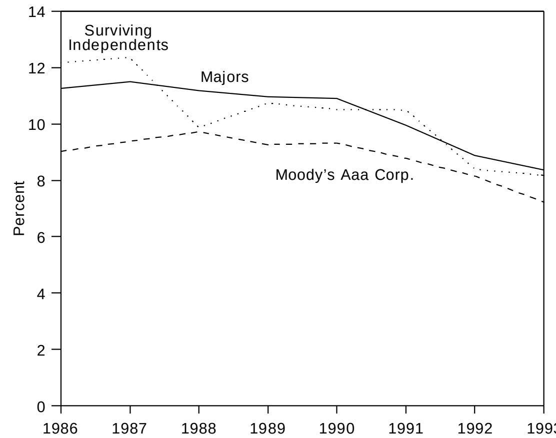
Although profitability has improved since the 1980's, return on equity for the independents has been persistently lower than return on equity for the majors and for the S&P 400 group of companies since 1986 (Figure 13). Coupled with their relatively high rate of reinvestment of funds and low payout to shareholders, this could indicate that the independents tend to overinvest in their own operations, allocating operating cash flow to relatively low-return projects, at least as measured by accounting rates of return.

Figure 14. Ratio of Market Value to Book Value for Majors, Publicly Traded Independents, and the S&P 400



Source: Compustat, a service of Standard & Poor's.

Figure 15. Effective Interest Rate for Majors and Publicly Traded Independent Oil and Gas Producers



Note: The effective interest rate is calculated by dividing interest expense by total long-term and short-term debt.

Source: **Independents and Majors:** Compustat, a service of Standard & Poor's; **Moody's Aaa Corporate:** Moody's Investor Service, *Moody's Industrial Manual 1994*, Vol. 1 (New York, 1994), p. a48.

Investor Risk and the Cost of Capital

The greater the chance of loss, the riskier the prospect of buying a company's stock or debt. In order to attract investment, a relatively risky firm must offer greater returns, in the form of higher dividend payments, greater growth opportunities, or higher interest payments on debt. One might expect given the risk of loss and lower returns in comparison with the majors (Figure 13), that the market would demand relatively higher rates of interest on debt issued by the independents. Surprisingly, this is not the case. The rate of interest (interest expense as a percent of long- and short-term debt) incurred by the independents was often slightly lower than the rate paid by the majors (Figure 15).

A closer analysis of another measure of investor perception of risk helps explain the apparent anomaly of the low interest rates paid by the independents. An investor can reduce the risk of loss within a portfolio of assets by purchasing a variety of stocks. As long as the returns from the stocks are not perfectly correlated with one another, adding even a relatively risky stock may reduce portfolio risk. The risk of owning the stock of an independent oil company can thus be reduced by diversification, and only the undiversifiable, or systematic, risk is relevant to the investor.

An often used measure of a company's systematic risk is "beta," which is the regression coefficient of stock value of a company with the value of the market. A stock with a beta value of one moves exactly with the market. If the market goes up 1 percent, the stock will go up 1 percent. A stock with a beta of less than 1 is less volatile than the market. If the value of the overall market decreases by 1 percent, the value of a stock with a beta of 0.8 will decrease by 0.8 percent. Thus, a stock with a beta of less than one is regarded as a valuable defense against a declining market.[28] Even highly volatile stocks may have low betas, as long as they do not tend to move with the overall market.

The beta values for the independents tend to be less than one, and following the oil price collapse, are usually less than the betas for the majors until 1992 (Table 5). This finding indicates that investors have been able to diversify away a substantial portion of the risk of investing in these companies. The independents' unexpectedly low interest rates reflect relatively low systematic risk.

Whether interest rates reflect systematic or unsystematic risk, the oil price crash appeared to increase the capital

[28]Alan C. Shapiro, *Modern Corporate Finance* (New York: Macmillan, 1990), p. 120.

Table 5. Average Betas for Majors and Surviving Independent Oil and Gas Producers

Year	Majors	Independents
1986	0.77	0.52
1987	0.96	0.75
1988	0.89	0.53
1989	0.97	0.80
1990	0.51	0.39
1991	0.79	0.60
1992	0.69	0.78
1993	0.62	0.84

Note: Betas reported are arithmetic averages, excluding observations with negative values.

Source: Rate of return information for calculating company-level betas: Center for Research in Security Prices (CRISP), University of Chicago. Company-level betas calculated using econometric methodology described in Energy Information Administration, *Investor Perceptions of Nuclear Power*, DOE/EIA-0446 (Washington, DC, May 1984).

markets' risk premium for investment in both the majors and the independents. The average interest rate for the independents was 30 percent higher than the Moody's Aaa rate on low risk corporate bonds in 1986, and the majors' overall interest rate was noticeably higher as well.[29] Since then, the gap between the rates has steadily narrowed, indicating a lessening of the risk premia demanded by investors of the majors and the independents.

Because the predominant source of external funds for the independents is long-term debt (and because, for any firm, the alternative to investing in one's own operations is simply to invest in other stocks and bonds), the rate of interest is a good reflection of the independents' cost of capital. The reductions in debt and improvement in profitability accordingly reduced their cost of capital, and the rates of interest paid by both the majors and the independents have approached the yield on low risk (rated "Aaa" by Moody's Investor Service) corporate bonds (Figure 15).

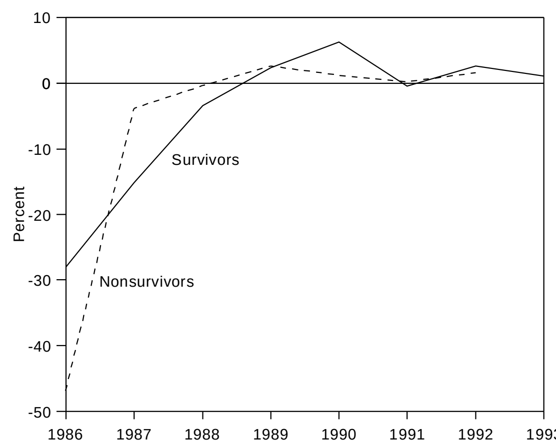
Characteristics of Surviving Producers

In 1985, 264 firms fit the classification (discussed in Chapter 3) of publicly traded independent oil and gas producer. By 1993, this number had decreased to 138, including new corporate entities that entered the U.S. oil and gas industry after 1985. What characteristics of performance distinguished survivors (and a handful of entrants) from the publicly traded independents that exited the industry?

Little Difference in Financial Performance

Survivor profitability, as measured by return on equity, was unremarkable in comparison with nonsurvivors (Figure 16). Given the lack of difference in return on equity, it is not surprising that the ratio of market value to book value for the survivors did not continuously exceed that of the nonsurvivors until 1990 (Figure 17).

Figure 16. Return on Equity for Publicly Traded Independent Oil and Gas Producers



Note: Return on equity is calculated as net income divided by stockholders' equity.

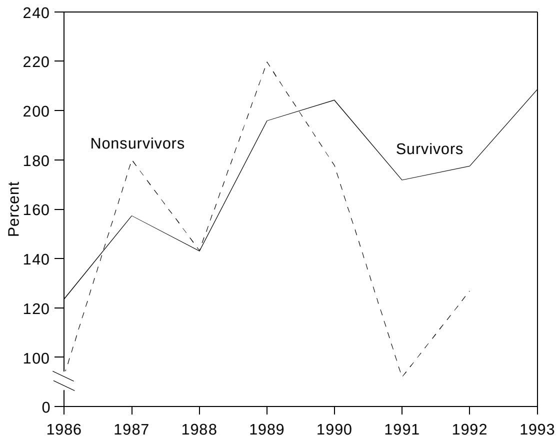
Source: Compustat, a service of Standard & Poor's.

The survivors carried more debt relative to equity than the nonsurvivors throughout the post-price collapse period (Figure 18). They also tied up relatively more cash in fixed interest payments than did the nonsurvivors (Figure 19). The greater reliance on debt may reflect an intentional strategy on the part of the survivors, or may have been the result of investor perception that these firms were a better bet for eventual repayment of debt.

The cost of capital for the surviving independents, represented by interest expense on total debt, has

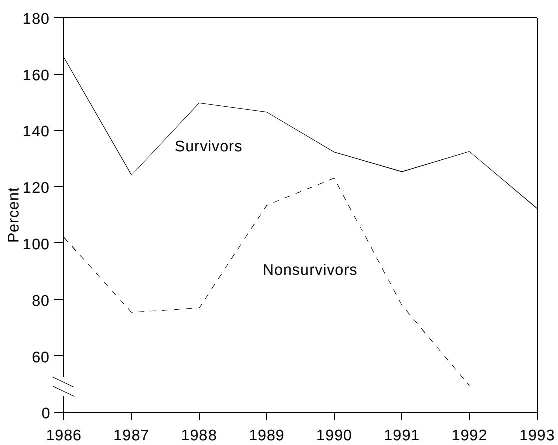
[29]The Moody's Aaa rate is given to corporate debt issues that have the lowest risk of default.

Figure 17. Market Value as a Percent of Book Value for Publicly Traded Independent Oil and Gas Producers



Source: Compustat, a service of Standard & Poor's.

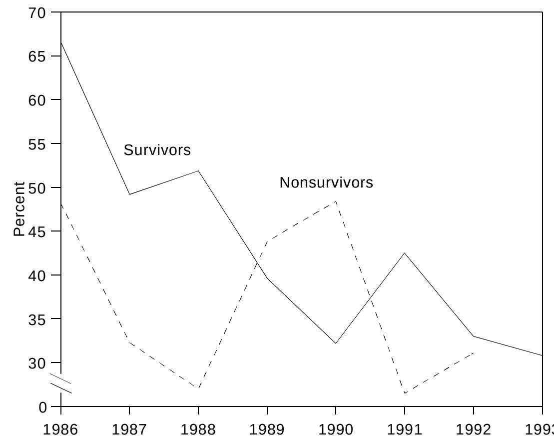
Figure 18. Total Debt as a Percent of Stockholders' Equity for Publicly Traded Independent Oil and Gas Producers



Note: Total debt is the sum of short-term debt, long-term debt, and accounts payable.

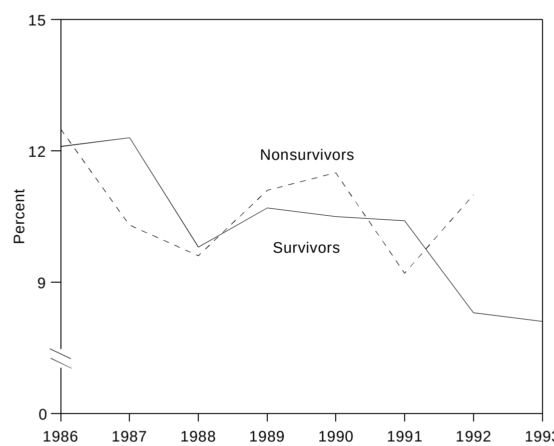
Source: Compustat, a service of Standard & Poor's.

Figure 19. Interest Expense as a Percent of Cash Flow for Publicly Traded Independent Oil and Gas Producers



Source: Compustat, a service of Standard & Poor's.

Figure 20. Interest Expense as a Percent of Total Debt for Publicly Traded Independent Oil and Gas Producers



Source: Compustat, a service of Standard & Poor's.

declined throughout the post-price collapse period (Figure 15). The decline reflected steadily falling long-term interest rates (e.g. Moody's Aaa rate) and a reduction in investors' perceptions of the riskiness of the independents. Still, the surviving independents paid about the same for borrowed funds as the nonsurvivors (Figure 20).

Low Reserve Replacement Costs Distinguish Survival

The one remarkable difference between the surviving and nonsurviving independent oil and gas producers was the cost of replacing oil and gas reserves. Throughout the post-price collapse period, the surviving independents (who began the period with slightly lower reserve replacement costs than the nonsurvivors) successfully added to reserves at ever lower costs than the nonsurvivors (Figure 9 in Chapter 4). By 1990, their costs were as low as those of the majors. This was a critical accomplishment for the independents, since the majors in general achieved lower costs by scaling back exploration, development, and reserve purchases, presumably dropping higher cost operations. The independents achieved lower costs in spite of the expansion of their U.S. reserve and asset base (Figures 1 and 8).

Appendix

Twenty-seven companies were initially notified of a requirement to file Form EIA-28 (Financial Reporting System). This group was initially chosen from the top 50 publicly owned U.S. crude oil producers, in 1976, who had at least 1 percent of either the production or the reserves of oil, gas, coal, or uranium in the United States or 1 percent of refining capacity or petroleum product sales in the United States. The list of companies required to report was updated for mergers, acquisitions, and spinoffs which, together with the selection criteria applied to 1991 data, resulted in the list of companies shown in the tabulation on the following page.

Table A1. Companies Reporting to the Financial Reporting System, 1977-1994

Company	1977-81	1982	1983-84	1985-86	1987	1988	1989-90	1991	1992-93	1994
Amerada Hess Corporation	X	X	X	X	X	X	X	X	X	X
American Petrofina Inc.[a]	X	X	X	X	X	X	X			
Amoco Corporation[b]	X	X	X	X	X	X	X	X	X	X
Anadarko Petroleum, Inc.									X	X
Ashland Oil, Inc.	X	X	X	X	X	X	X	X	X	X
Atlantic Richfield Co. (ARCO)	X	X	X	X	X	X	X	X	X	X
BP America, Inc.[c]					X	X	X	X	X	X
Burlington Northern Inc.[d]	X	X	X	X	X					
Burlington Resources Inc.[d]						X	X	X	X	X
Chevron Corporation[e f]	X	X	X	X	X	X	X	X	X	X
Cities Service[g]	X	X								
Coastal Corporation	X	X	X	X	X	X	X	X	X	X
Conoco[h]	X									
E.I. du Pont de Nemours and Co.[h]		X	X	X	X	X	X	X	X	X
Enron Corporation									X	X
Exxon Corporation	X	X	X	X	X	X	X	X	X	X
Fina, Inc.[a]								X	X	X
Getty Oil[i]	X	X	X							
Gulf Oil[f]	X	X	X							
Kerr-McGee Corporation	X	X	X	X	X	X	X	X	X	X
Marathon[j]	X									
Mobil Corporation[k]	X	X	X	X	X	X	X	X	X	X
Nerco, Inc.[l]									X	
Occidental Petroleum Corporation[g]	X	X	X	X	X	X	X	X	X	X
Oryx Energy Company[m]						X	X	X	X	X
Phillips Petroleum Company	X	X	X	X	X	X	X	X	X	X
Shell Oil Company	X	X	X	X	X	X	X	X	X	X
Standard Oil Co. (Ohio) (SOHIO)[c]	X	X	X	X						
Sun Company, Inc.[m]	X	X	X	X	X	X	X	X	X	X
Superior Oil[k]	X	X	X							
Tenneco Inc.[n]	X	X	X	X	X	X				
Texaco Inc.[i]	X	X	X	X	X	X	X	X	X	X
Total Petroleum (North America) Ltd.[o]							X	X		
Union Pacific Corporation	X	X	X	X	X	X	X	X	X	X
Unocal Corporation	X	X	X	X	X	X	X	X	X	X
USX Corporation[j]		X	X	X	X	X	X	X	X	X

[a]American Petrofina, Inc. changed its name to Fina, Inc. effective April 17, 1991.

[b]Formerly Standard Oil Company (Indiana).

[c]In 1987, BP America acquired all shares in Standard Oil Company (Ohio) that it did not already control.

[d]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.

[e]Formerly Standard Oil Company of California.

[f]Chevron acquired Gulf Oil in 1984 but separate data for Gulf continued to be available for the full 1984 year.

[g]Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.

[h]DuPont acquired Conoco in 1981. Separate data for Conoco were available for 1981, DuPont was included in the FRS system in 1982.

[i]Texaco acquired Getty in 1984, however, Getty was treated as a separate FRS company for that year.

[j]U.S. Steel (now USX) acquired Marathon in 1982.

[k]Mobil acquired Superior in 1984 but both companies were treated separately for that year.

[l]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.

[m]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.

[n]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.

[o]Effective June 1, 1991 Total's exploration, production and marketing operations in Canada were spun off to Total Oil & Gas, a new public entity.

Note: "X" indicates that the company was included in the FRS system for the year indicated.

Source: Energy Information Administration, Form EIA-28.