Chapter 6

Changes in the Oil Industry Affecting U.S. Oil Production

Changes in the Climate for Oil Investments in the United States and Overseas

The United States represents the most "mature," most intensively drilled of the world's petroleum regions, yet continues to attract a lion's share of exploration and development expenditures. The raw statistics—70,000 barrels found per U.S. wildcat well v. 7 million per wildcat for the rest of the world—paint too extreme a picture of the United States' geologic inferiority, because the nature of its infrastructural development makes economic many low-payoff drilling ventures that could not be attempted elsewhere. It is nevertheless true that geological prospects generally are far superior overseas than in the United States, particularly the Lower 48 States, yet the major oil companies, most based in the United States, continue to spend most of their capital domestically.

An important reason for this appears to be the greater stability and security available within the United States. The major oil companies learned **a** harsh lesson when the Middle East OPEC nations nationalized their oil production and transformed these companies from producers to buyers. Also, the governments of many oil-bearing countries offered only relatively harsh terms for development of their oil resources. Their strategy was stimulated by the belief that oil prices would continue to rise, so that they could benefit by withholding their resources for later development (at much higher prices).[1] **In addition, until recently, hostility to foreign, private investment** of any sort was common among the developing nations.

Industry analysts claim that the business climate for overseas oil investment is improving relative to that of the United States and that, in response, oil company attitudes towards overseas investment are shifting. Industry experts at an OTA workshop unanimously agreed that the large oil companies were shifting their attention to overseas drilling prospects. A recent Salomon Bros. survey found that U.S. oil companies expect to spend 29 percent of their 1987 budgets outside the United States compared to 12 percent in 1986.[2]

Presumably, the reasons for the improving climate are twofold. First, the developing nations have become more sophisticated both economically and politically. They have come to appreciate the potential benefits of private and foreign investments and do not fear as much as previously the accusation that they are selling out to foreign interests. Second, they have come to **recognize**, in light of falling prices, that the delay of oil and gas development has created a substantial loss, rather than a gain, in investment value. These shifts in attitude and understanding have been translated into a variety of concrete actions designed to attract oil and gas investment, **including:**

- removal or raising of former caps on prices paid to foreign producers (Angola, Color-n-bia, Morocco, Canada, Turkey);
- contractors now paid in dollars rather than local currency (Argentina, Chile);
- removal or reduction of prior oil taxes (Canada, Morocco, Trinidad, United Kingdom);
- reduction of royalty rates (Canada, China, Morocco, United Kingdom);
- easing of requirements for training and employing nationals (China);
- flexibility in shifting lease areas (China);
- tax **or** royalty relief for areas deemed difficult **to** explore (Chile, it-eland);
- customs taxes waived for imported materials needed for oilfield operations (Chile);

[1] See M.A. Adelman, "World Oil: Availability and Price: The Next Ten Years," Asian Development Bank, Regional Meeting on Energy Policy, Dec. 11-12, 1986.

[2] *Oil and Gas Journal,* Feb. 23, 1987, p. 30.

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- government loans for seismic surveys, exploratory drilling, etc. (Korea); and
- a variety of more favorable tax and cost recovery rules and other incentives.[3]

Oil industry spokesmen claim that the United States, in contrast to most other countries competing for oil investment, has enacted tax and regulatory changes that substantially worsen the business climate for oil and gas investment,[4] and weaken the Nation's ability to attract such investment. For example, the American Petroleum Institute claims that the 1986 Tax Law will cost the industry $10 billion over the next 5 years, and that the potential reclassification of drilling wastes to the hazardous category by the Environmental Protection Agency could cost the industry up to $8 billion annually.[5]

Evaluating the relative "business climate" for petroleum investments of the United States versus competing foreign nations is difficult. It is dependent on the type of investment being contemplated, the differences in geologic situations, the complex tax, royalty, and regulatory structures in the United States and abroad, differences in the availability of skilled labor and other factors of production, and impossible-to-measure differences in political stability and physical security. In general, we are impressed with the **failure** of most discussions of the opposing climates to deal with the above factors in a careful fashion, and we warn against drawing simplistic conclusions. Also, overseas oil investment can be beneficial to U.S. national security because increased reserves and production outside of the Middle East increases market stability and diffuses the potential for embargoes and price shocks. Thus, although it probably is fair to claim that the **relative** attractiveness of overseas investment is improving vis-a-vis domestic investment, it is not clear whether this shift is towards or away from a desirable balance of overseas and domestic investment.

[3] Barrows Company Inc., New York, NY, "World Incentives for Petroleum Investment, 1980-1 986, " prepared for the United Nations Department of Technical Cooperation for Development.

[4] See, for example, American Petroleum Institute, Two *Energy Futures: National Choices Today for the 1990s, 1986* edition, July 1986.

[5] "API Counts the Burdens of Regulation, " *The Energy Daily,* Dec. 2, 1986.

The Efficiency of E&D Activities

As drilling budgets and other indicators of E&D activity have declined in the face of sharply lower oil prices, the results of that activity, in new fields discovered, volumes of oil added to reserves, and added production capacity also would be expected to decline. However, it is unlikely that these results will drop precisely in lock step with the declines in activity levels, because the "efficiency" of this activity is likely to change also. Understanding how the various measures of efficiency might change is important to projecting future oil reserve additions and production levels.

Few if any of the measures of efficiency in exploration and development have remained stable over the past decade and a half. Such efficiency measures as finding costs (reserves added per dollar spent on exploration and development), rig efficiency (annual footage or wells drilled per active rig), finding rate (reserves added per well or per foot drilled), and completion rate (successful wells/total wells drilled) have varied substantially as oil prices and overall industry activity has ridden a cycle of boom and bust. Because these measures have in the past been so sensitive to changes in economic conditions and especially to changes in oil prices, they are likely to have shifted dramatically–and possibly to continue to shift-in the face of the severe economic dislocations of the past several months.

As an example, finding costs escalated rapidly during the 1970s and very early 1980s, **peaked in 1982 at $13.53/bbl (including revisions) and then have slid substantially in the face of declining oil prices.[6] Reliably projecting future finding costs is critical to projecting future production, and especially critical to production projections that rely on first predicting capital spending and then calculating** reserve additions by using the equation:

Reserves added = (Capital Spending) /(Finding Costs)

To project likely future finding costs, it is necessary both to understand the relationship be-

[6] Arthur Andersen & Co., op. cit. Note that the authors call these values "surrogate" finding costs because they combine expenditures made and reserves added **in the same year,** whereas true finding costs would match expenditures to the actual reserves these expenditures created, usually a few years later.

tween finding costs and the variables affecting them, and to predict the future values of these variables. Unfortunately, finding costs—like the other efficiency measures—are functions of several variables, some of which cannot be easily tracked. These variables, which are not independent of each other, include oil prices, drilling and other service costs, drilling strategies (especially the relative emphasis on deep drilling and other high cost drilling), resource depletion, the availability of promising exploratory acreage, and the technical efficiency of exploration and production technologies. In general, rising oil prices have led to rising finding costs, and vice versa, largely because higher prices stimulate activity aimed at smaller reserve targets or higher cost environments, and lower prices force operators to focus on higher quality (lower finding cost) targets. The past few years have seen sharply decreased finding costs. A fair expectation is that finding costs will remain low if oil prices remain depressed. However, this is not certain, and it will be difficult to predict the magnitude of finding costs with any precision. For example, the energy economist Arlon Tussing, in his testimony of March 6, 1986 to the House Energy and Commerce Committee, predicted that the slide in finding costs that began in 1982 would be found to have continued into 1985, with costs declining about $1.50/bbl from their 1984 value. The recently published Arthur Andersen survey found, however, that 1985 finding costs had gone up from 1984's costs by about $1/bbl, presumably because of the relatively low reported 1985 reserve additions as well as a 7 percent increase in completed well costs.

Another efficiency measure, so-called "rig efficiency" (footage and wells drilled per rig per year), declined from the middle 1970s to the early 1980s as oil prices rose and oilfield activity accelerated. Part of this decline was due to the use of inexperienced personnel and marginal equipment, made possible by the inability of the supply of services to keep up with the demand. Part was due to the spread of drilling activity to more marginal prospects, with lower reserves and perhaps more difficult drilling conditions, and to high payoff but high cost prospects–like deep gas–that required more rig time; this was partly a result of the improved economics of these prospects, and partly an effect of resource depletion as the best prospects were used up,

As oil prices began to decline in 1981, drilling became more efficient as the number of inexperienced drilling crews declined, inefficient rigs were dropped from service, footage and turnkey contracts replaced contracts that paid drillers by the day (day rate contracts offered little incentive for efficiency), and drilling technology improved . . . and thus rig efficiency increased sharply between 1981 and 1985: the industry drilled 89,000 wells in 1981 with nearly 4,000 rotary rigs active; 84,000 wells in 1982 with 3,100 rigs active; and 85,000 in 1984 with 2,400 rigs. Unfortunately, however, the precise dimensions of the actual increase in efficiency are obscured by other factors that also affect measured rig efficiency. These factors include: the proportion of total drilling devoted to exploration, because exploratory drilling is more time-consuming than development drilling; possible changes in the number of rigs that are not included in the data[7]; shifts in the balance of drilling for gas and for oil, because gas wells often require more rig time than oil wells; and shifts in the geographic distribution of drilling, because drilling in some areas, such as the gulf coast, is more rapid than in others, e.g., the Midcontinent and Rocky Mountain Overthrust Belt, because of different rock conditions and other physical factors. Although OTA is not aware of analyses that have systematically isolated the effects of the various factors influencing rig efficiency, several of our reviewers believe that shifts in drilling targets areas important as actual changes in drilling equipment and operational efficiency as causes of the changes in rig efficiency over the past decade and a half.

Another measure critical to many forecasting methods is the "finding rate" of drilling, measured in reserves added per well drilled. s The decline in drilling now occurring, and expected to

[7]Commonly used rig counts include only so-called rotary drilling rigs, rigs that drill by rotating a drill bit and its attached drilling pipe.

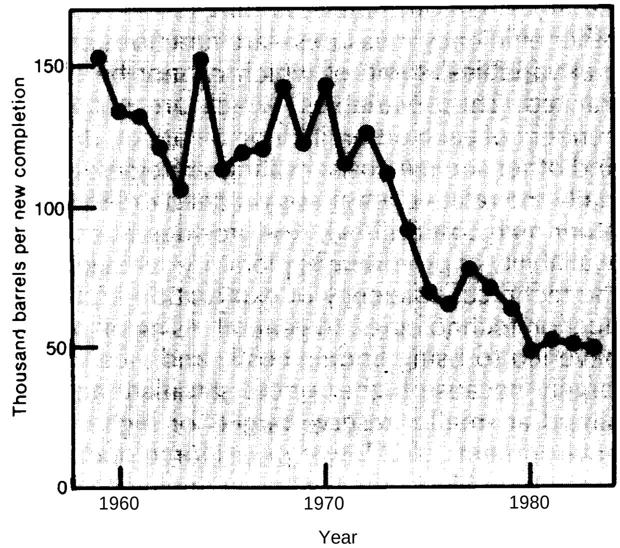
[8]There are other measures of finding rate, for example, reserves added per exploratory well. Problems in tying together "reserves added' and the specific activities that "created" these reserves are endemic to oil and gas analysis, and no particular measure of finding rate can escape these problems,

continue, will certainly not be so uniform as to leave the finding rate untouched; a 50 percent decline in drilling is unlikely to yield a 50 percent decline in reserve additions except by some unlikely coincidence.

Figure 9 shows the change in oil finding rate from 1960 to 1983, with "reserves found" computed by assuming a time lag between exploratory drilling and reserve development of 4 years for onshore drilling and 7 years for offshore.[9] The drop in finding rate beginning in the early 1970s may be partly because of resource depletion, but common sense implies that, because of improved economics associated with higher oil prices, a substantial role must have been played by increased drilling of marginal prospects within each region, as well as increased drilling in less productive regions. **The** role of shifting drilling patterns is complicated by the observation that, during the same period, some explorers responded to the price increases by drilling in expensive, high risk regions that promised very high returns per well. However, the lack of exploration success in many of the new drilling areas and the huge number of new marginal wells that were drilled sustain the above interpretation.

OTA believes that the average finding rate achieved by the smaller number of wells being drilled in 1986 might be somewhat higher than recent historical rates; in other words, OTA believes that the finding rate is likely to swing back up the curve in figure ***9.*** Some insight into the potential increase in finding rate can be gained by examining recent regional shifts in drilling. Short-term changes in drilling patterns, as projected by the Oil and Gas Journal,[10] imply that drilling declines will be greatest in areas with relatively low finding rates. Because finding rates differ greatly from region to region, such a shift has great potential to change the national finding rate. For example, adopting the assumption that 1980 to 1984 regional finding **rates will still be reflected in 1986 drilling will result** in an estimated national finding rate for 1986 that is 40 percent higher than the 1980 to 1984 national rate, if the projected shift in drilling patterns holds. This in turn would yield 1986 reserve additions for the United States that would be considerably higher than would be projected assuming a 1 -to- 1 relationship between reserves and drilling rates: specifically, 2.2 billion barrels for the regionally adjusted value versus 1.6 billion barrels without the adjustment, assuming that 46,000 wells (including dry holes) are drilled in 1986. '

Figure 9.—Oil "Finding Rate" (Reserves Added per Oil Well)



SOURCE: A T Guernsey, ***Profitability Study,*** *Crude* ***Oil and Natural*** *Gas* ***Exploration, Development,*** *and* ***Production Activities in the*** *USA, 1959-7983,* June 1985 for Shell 011 Co

OTA does not believe that the "regionally adjusted" estimate of 2.2 billion barrels is the "right" value for 1986 reserve additions. A variety of other factors, such as intraregional shifts in drilling, must still be accounted for. In particular, oil companies are predicting a significant shift away from exploratory drilling towards low risk development drilling; such a shift would tend to lower finding rates and thus lower reserve additions. Also, in the years following 1986, drilling patterns will continue to change even if prices do not. A portion of near-term drilling is tied to

'A. T. Guernsey, *Profitability Study. Crude Oil and Natural Gas Exploration, Development, and Production Activities in the USA, 1959- 1983,* for Shell Oil Co., June 1985.

[10] " OGJ's Revised Drilling Forecast for 1986—U.S. and Canada, " Oil and Gas journal, July 28, 1986, p. 67.

[11] Ibid. It is further assumed that the ratio of completed 011 wells to completed gas wells established in 1980 to 1984 will hold tor 1986.

present lease and other commitments, and these will expire. Company strategies will change, especially since current drilling behavior is affected substantially by its nearness in time to the recent price shock and the turmoil it created. As discussed above, the industry is in a period of transition, and it is far from clear what its exploration and development strategies will look like a few years from today.

Despite the uncertainties created by these factors, it is useful to project future domestic oil production levels by using a "what if" scenario that assumes a continuation of the projected 1986 drilling levels and the optimistic value for reserves/well that reflects only the new geographic distribution of drilling without accounting for factors that might reduce the reserves/well value. The results of just such a projection are discussed in detail in chapter 7.

Changing Oilfield Technology

Continuing evolution of the technology of oil exploration, development, and production is likely to play an important role in the basic economics of oil exploration and development and the size and rate of exploitation of the recoverable oil resource base. For example, advancements in seismic technology that allow for both finer resolution and significant reductions in data collection and analysis costs will be crucial in finding and producing the many thousands of small oil and gasfields. Technological advancements that will substantially decrease production costs—e.g., subsea production systems—are critical to developing offshore fields at today's low. oil prices.

Unfortunately, analysts have had little success at trying to quantify the effects of technological change on oil development. For one thing, there is enormous variability of technical requirements across different prospects, so patterns of technological use are difficult to track. Also, technical capability varies widely among oilfield operators, so that different operators working in the same field and same physical conditions may choose different technical approaches. In our interviews with oilfield operators, OTA was struck by their differing assessments of the importance of technological changes in the past and the potential for such changes in the future. Some describe the past decade and a half as a time of only modest technological change; others describe "tremendous advances in exploration and extraction technologies." [12] It is OTA's impression, however, that the majority of oilmen are pessimistic about the potential for technology to make a big difference in costs in most situations. in particular, oilmen point to the failure of new exploration technology to cause a measurable change in dry hole risk, and the steady downward progression of performance measures such as reserves added per well.

OTA believes that technological change has played an important role in oil exploration and development during the past decade or two, but that other forces affecting oil markets, especially the price shocks following the Yom Kippur War and the Iranian revolution, obscured the effects of technology. Most importantly, the hyperinflation of oilfield services starting in the middle 1970s simply overwhelmed any statistical evidence of the many cost-cutting effects of new and evolved technologies, Nevertheless, the following technological changes clearly played a significant role in stimulating the movement of resources into the recoverable range, whether by affecting the economics of prospects that previously could have been recovered but had insufficient profit potential, or by moving resources out of the technically unrecoverable range to the recoverable:

- significant improvements in the longevity of drill bits;
- movement of seismic interpretation from strict reliance on mainframe computers to widely available minicomputers, and the development and spreading use of 3-D seismic techniques;
- numerous advances in enhanced oil recovery technologies;
- development of subsea completion and floating production systems, that both allow

[12] H. R. Linden, "Impact of Advances in Science, Technology and in the Understanding of the Terrestrial Origin of Hydrocarbons on the Role of Natural Gas and Crude Oil in Meeting Future Primary Energy Needs," Gas Research Institute, July 18, 1986.

the exploitation of smaller offshore fields and lower the risk of certain high-risk large fields;

- improvements in offshore platforms, especially movement to lighter, less expensive designs (e.g., the tension leg platform);
- development of measurement-while-drilling techniques[13] that help avoid mishaps, permit more accurate directional drilling, and reduce the probability of missing productive zones;
- continuing evolution of various subsystems, e.g., drilling mud systems;
- development and/or improvement of sophisticated nonseismic exploration techniques, including remote sensing techniques and geochemical techniques;
- vast improvement in fracturing techniques for low-permeability reservoirs, especially critical for gas recovery;
- development of horizontal drilling techniques that allow economic recovery from thin pay zones and promote full field development at lower costs; and
- development of more sophisticated mathematical models for reservoir simulation that allow better design of well placement for field development.

OTA has become aware of several recent technological improvements that demonstrate the potential of advanced technology to make important changes in the economics of exploration and development:

- A factor of two improvement in the resolution capability of seismic imagery, which has important implications for development well placement and exploration for small fields.
- The recent development of improved nuclear logging tools that can detect oil and gas behind well casing. This will allow the identification of producing zones that were missed during initial exploration, with particular implications for increasing production from existing wells.
- The development of so-called stratigraphic-seismic techniques which can improve exploratory well success.
- New methods of 3-D seismic mapping of reservoirs that provide similar detail at half the cost of previous approaches. Although 3-D seismic is a powerful exploratory and development drilling tool, its use has been limited because of its cost.
- New developments in chemical enhanced oil recovery (EOR) that have lowered the threshold of profitable application from $25 to $30/bbl to about $20/bbl for this type of EOR. This will offer major opportunities for implementing EOR more widely than previously expected, with higher recovery efficiencies.
- New techniques for three-phase flow measurements of oil, water, and gas that will allow the elimination of expensive test separators in offshore platforms, lowering somewhat the economic threshold for offshore recovery.
- Substantial decreases in the cost of multicomponent seismic imagery, which uses standard compressional waves in combination with shear waves to allow higher spatial resolution, direct identification of rock types, measurement of porosity and permeability and direct hydrocarbon detection. A new multicomponent seismic source costs only about 50 percent more than compressional seismic, which will open this technology to practical application.
- The initial uses of CAT scanning to observation of flow inside porous rocks. Continued research should lead to improved mathematical modeling of non-uniform flow inside reservoirs, critical to optimizing EOR design.
- The first Alaskan well using "extended reach horizontal drilling" was drilled by Standard Oil and tripled the output of conventional drilling in the same formation. By allowing the development of areas where the pay is too thin to develop with conventional drilling, it is hoped that this technique will allow increased recovery at Prudhoe Bay.[14]

The continuing development of new and improved technologies, especially focusing on cutting costs, will be a crucial determinant of the fu-

[13] Measurement of rock permeabilit, and porosity, hydrocarbon presence, and other important variables without shutting down drilling and removing the drill "string."

[14] Arlon R. Tussing & Associates, Inc., *The Property-Tax Base of the North Slope Borough, Alaska,* May 1, 1986.

ture success of the industry in reducing the decline in oil reserves and production rates expected to accompany lower oil prices. Although the level of effort in oilfield R&D is difficult to track because it is hidden in many different accounting "cub byholes," most industry observers feel that it has been cut back substantially. For example, the former president of Exxon Research & Engineering Co. has estimated that research, development, and engineering within the industry has been cut by at least 30 to 40 percent in the last 3 years.[15]

If the observers are correct, and if the industry wishes to be able to prevent large production drops, the industry probably is doing the opposite of what it should be doing, despite its need **to** economize in response to drastic cuts in revenues. In the face of drastic changes in their economic environments, other industries have achieved large cuts in production costs. It seems reasonable to project that the oil industry would stand a good chance of achieving the same.

According to the French Petroleum Institute (Institut Francais du Petrole, or IFP), potential near-term improvements in oilfield technology can offer very substantial cost savings. IFP identifies key advances as:

- optimization and automated control and management of drilling, based on the most sophisticated use of measurement-while-drilling, offering a potential reduction in drilling cost of 30 to 35 percent;
- optimization of the understanding of reservoirs as the result of progress in the modeling of their dynamic behavior, leading to better well placement and the need for fewer development wells;
- further development of seismic imagery to help in understanding reservoir behavior, including increasing its power of resolution to provide detailed images of the reservoir; development of seismic devices that can operate inside the well bore, leading to the same result as above as well as a higher success rate for exploration wells;
- improvement in enhanced recovery techniques, including drilling techniques such as horizontal drilling; and
- continued improvement in offshore platforms for shallower waters, and development of "all on the bottom" systems for deeper waters.[16]

IFP estimates that full success of such a technology development program and its successful implementation could create substantial savings in the overall technical costs of production (including exploration and development costs), namely:

Onshore fields .... savings of 20 to 25 percent
Conventional offshore fields savings up to 30 percent
Deep offshore fields:...................... savings of 30 to 50 percent[17]

If the IFP estimates are valid, then technological advances could move a large share of petroleum resources from the subeconomic to the economic range at $15 to $20 oil prices. The majority of industry reviewers of the draft version of this report were quite skeptical of the **IFP** estimates and felt they were substantially overoptimistic. There were, however, a minority of "technology optimists, " some of whom are familiar with current research and development programs, who are hopeful about the potential for achieving cost savings of this magnitude. These hopes are, of course, dependent on the industry somehow resisting the current trend towards reduced R&D expenditures and focusing a substantial effort on cost-saving technology.

Deteriorating Industry Infrastructure and the Potential for a Rebound in Oil Production

Introduction

Although the current decline in U.S. domestic oil production and the expected further production declines are dismaying in and of themselves, the declines translate into problems for U.S. national security and economic stability only to the extent that production levels cannot rebound

[15] Edward E, David, quoted in the "News and Comment' section of Science, vol. 232, June 27, 1986.

[16] J. Favre, "Research and Innovation To Get Out of a Crisis: The Cost-Reduction Policy of the Institut Francais du Petrole," presented at the Conference on Impact of Price Declines on Oil Exploration, Development and Financing, Dallas, TX, Sept. 3-5, 1986.

[17] Ibid

soon after the onset of a physical shortage of oil or a large increase in its price. In fact, if production **could rebound in this way, future disruptions might be less probable.**

In general, a decline in domestic production will not be easily reversible. it is true that some of the wells that are shut in can be placed back in production (although the number of such wells will diminish sharply after a few years). I n addition, some EOR projects that are moth balled can be restarted (although it may take a few months for additional production to start flowing and the production response to the EOR may be reduced). In general, however, significant amounts of incremental production can be added only by reworking old wells, by drilling new ones, both exploratory and development, and by developing new EOR projects or expanding existing projects. All of these activities are capital-, manpower-, and equipment-intensive, and gaining significant increments of production—which will require tens of thousands of individual drilling and other projects—will be time-consuming even if capital, equipment, and manpower are plentiful.

There are now substantial doubts as to whether capital, equipment, and manpower **will** be plentiful, given the deterioration of the industry's infrastructure that has occurred over the past few years and the loss of the confidence in steadily rising oil prices that marked the rapid buildup of industry infrastructure that took place in the 1970s, Many in the oil industry are arguing that, once U.S. oil production declines to levels well below those of today, a production rebound in response to a sudden price hike would be extremely slow, would be accompanied by massive inflation in equipment and manpower costs (as well as inflation in associated costs such as leasing bonuses), and would likely fall well short of recapturing the losses in production rates. Examining this hypothesis requires an evaluation of the factors of production and the timetables for each phase of the production cycle.

People

There is widespread concern in the industry that the current depression in E&D activity and the accompanying layoffs, company failures, and crippled hiring programs will rob the industry of a major portion of its most valuable personnel. Overall industry employment has dropped from its 1982 high of 708,000 to 425,000 in August of 1986. Oilfield service company employment dropped from 435,000 to 206,000 in the same period, indicating that this sector has absorbed the brunt of the layoffs. A special concern is that the very pessimistic perception on college campuses of the industry's future and the virtual halt of industry recruitment efforts will decimate well-established university programs in petroleum geology and engineering. Another concern is that many of the employee reduction programs are focusing on the older, more experienced (and more highly paid) professionals, and that the industry is thus losing its most effective workers. This concern is intensified by the 3-year training period said to be necessary for skilled oil service workers and the 7- to 10-year period needed for professionals.

The seriousness of these concerns is by no means settled. For one thing, the drilling boom of the late 1970s and early 1980s attracted very large numbers of students to petroleum-related programs. For example, the Society of Petroleum Engineers reports that a large oversupply of petroleum engineering graduates has existed since 1980-81, and expects this condition to last at least through the end of the decade. This situation probably exists in other petroleum fields as well. Although many of these graduates as well as the laid off engineers, geologists, and other professionals and skilled workers will find work in other fields, it is by no means certain that they will be "lost" to the industry. Previous experience with other industries—e.g., in aerospace technologies —implies that many of these trained personnel can be recaptured by the industry in the event of a sudden leap in oilfield activity, at least if there is convincing evidence that the new jobs will be stable. Further, the possibility of "recapture" should be strongly influenced by the attractiveness of replacement jobs. Although OTA is not aware of data on the success of laid-off oilfield workers in finding employment, and on the relative salary levels of replacement jobs, laid-off manufacturing workers in similar situations have tended to take substantial salary cuts, and oilfield workers would likely have to do the same.

Capital Availability

The opportunity for a rapid rebound in oil production will be possible only with a large increase in cash flow, presumably from a substantial oil price increase, or a massive influx of outside capital into exploration and development activities. During the drilling boom of the 1970s and early 1980s, attracting such capital was relatively easy because of favorable tax policies and because of a widespread perception that inexorable increases in oil prices would rescue even weak investments so long as some producible oil was found. In contrast, capital availability to fuel a potential production rebound is likely to depend primarily on skeptical analyses of the economic fundamentals of the individual oil prospects using conservative assumptions about future price growth. Investors will have to be convinced that the economic conditions appearing to favor new oilfield investment are stable, or else that their investment will be safeguarded against a return to low prices. Consequently, the potential for a successful rebound in U.S. oil production will depend strongly on the precise geopolitical circumstances—and the perceptions of these circumstances—that accompany the events driving the oil market towards shortages and/or sharply higher prices. Also, because perceptions and reality clearly do not have to—and often do not—agree, and because a variety of unpredictable factors fuel perception, considerable uncertainty exists about the potential response of capital markets to an oil market situation in which a rebound might be attempted.

Some analysts, seeing that the independent producers' supply of outside capital (from banks and private and public drilling funds) has virtually disappeared, and recognizing that internal cash flow was the primary source of the industry's investment dollars even when outside capital was readily available, assume that any rebound will have to be funded from internal funds. In OTA's view, this is unrealistic. The current withdrawal by banks and funds from oil investment seems a logical short-term response to the large financial losses sustained by these capital sources and the widespread perception of massive instability in oil prices. Eventually, however, a portion of these capital sources will return to the industry if profitable investment opportunities are perceived to be available. The timing of this return, however, being as much a psychological event as a financial one, is highly uncertain.

It is also important to recognize that **the drying** up of internal capital is not universal to the industry, because many of the integrated companies retain substantial cash flows from their downstream operations, and even the reduced cash flows from production can buy considerably more drilling services than would have been possible in the early 1980s, **because of the substantial reductions in oilfield costs.**

Equipment

Equipment availability is an additional concern in the event of any attempt at a rapid restoration of lost U.S. oil production. As noted above, such a restoration will involve the drilling and equipping of many thousands of new wells in addition to the completion of thousands of other production-related and equipment-intensive projects.

Although the industry has expressed substantial concern about equipment availability, there currently is a substantial surplus of oilfield equipment both in a ready status and in storage. At the peak of the drilling boom in 1981 there were over 5,000 land drilling rigs available in the United States, the majority of them constructed within a few years of that date. Although utilization rates were high during the boom (79 percent in 1981, for example), most industry observers will agree that rig efficiency was low. Indeed, the industry drilled nearly 86,000 wells in 1984 using only 2,400 rigs, whereas nearly 4,000 rigs drilled 89,000 wells in 1981.[18] Also, many of the wells drilled in 1981 were drilled with only marginal prospects for success. A more efficient industry could have added the same volume of reserves with far fewer rigs than were actually deployed.

[18] Some part of the difference in rig efficiency is said to be due to a reduction in deep drilling for gas after 1981. Average well depth declined by only 250 feet during the period, however. Other factors aside from actual improvements in equipment and operational efficiency that may have contributed to rig efficiency changes include shifts in the locational distribution of drilling and changes in the proportion of exploratory drilling.

Although a "target" rig count for a successful rebound is a speculative figure at best, a return to a 3,000- or 4,000-rig onshore fleet seems excessive. If a 2,500 rig count is a reasonable target level for a production rebound, it appears likely that the capability for quickly assembling that size fleet will remain viable for at least several years. Although some of the used equipment has been sold to foreign operators, overseas activity levels seem unlikely to expand sufficiently to warrant concern over additional losses. Other areas of concern include the cannibalization of rigs to keep the current fleet operating, the potential for scrappage, and the potential for deterioration due to improper storage. Cannibalization is occurring and will eat into rig availability, but there are so many excess rigs that this should not be a major problem for a considerable time. Little of the equipment is likely to be scrapped, however, because in most cases the price of scrap steel is low, and dismantling is expensive. Finally, although concerns about proper storage are well founded, much of the equipment now out of service is simple and durable (see table 31), and the best rigs are the most likely to be properly moth balled and maintained. An indication **of industry recognition of the value of proper storage is the formation of** services designed to handle some or all aspects of storage for rig owners.[19]

In conclusion, although an attempt to add quickly to drilling rates will likely run into some bottlenecks, especially in high volume goods such as drill pipe and drill bits, for the next few years equipment should not be a major constraint on a drilling revival.

The Resource Base and Availability of E&D Opportunities

The turnaround in U.S. oil production that took firm hold in the late 1970s owed much to the large "inventory" of potential drilling opportunities amassed during the previous decades of low oil prices. By going back to old well logs and field records, geologists and engineers could identify many thousands of opportunities that were uneconomic at $3/bbl yet low-risk, profitable producers at $10 and up. Although most were modest producers, in the aggregate they made a significant contribution to total U.S. production. In addition, Alaskan production was just beginning to start up in the early 1970s and provided an additional, massive boost to U.S. production levels.

[19] L. R. Aalund, "Rig Owners Grapple With Offshore Stacking," *Oil and Gas Journal,* Sept. 15, 1986.

Table 31.—Drill Rig Equipment: Storage and Availability

Derrick: The derrick is made to be stored in the open, and should not present a problem.

Mud pumps: Mud pumps should be stored out of the weather, but are relatively easy to store. Lots of upgrading was done to the fleet's mud pumps in 1983 to 1984, and most should be in good condition.

Drill pipe: Drill pipe is quite likely to be sold off and may represent a high potential for a *short-term* shortage in case of a rebound in drilling activity.

Draw works: Draw works are vulnerable to the elements, but still relatively easy to store properly.

Prime ***movers:*** Engines are most likely to be sold to other industries, and could be in shortage in a rebound.

Drill bits: Since drill bits do not last long, a rebound will require substantial bit manufacturing capability. This capability is being rapidly diminished, and drill bits may be in shortage in a rebound.

SOURCE Office of Technology Assessment, based on discussions with equipment suppliers.

Prospects for a rebound in production following a substantial price increase will depend in large measure on whether or not a similar inventory exists now of drilling and other production-related opportunities. Without such an inventory, a substantial boost in production would have to wait a number of additional years to work through the early stages of the production cycle . . . stages that are bypassed when low risk opportunities in discovered fields can be identified. The importance of such an inventory is further enhanced by the imminent decline of Alaskan production and the lack of any replacement producing province.

The issue of whether or not the inventory of oil opportunities will be adequate to support moderate levels of drilling activity for a number of years is basically the same issue of continued field growth that appears in Section Vd on the Resource Base. As discussed in that section, there remains substantial controversy about the potential for field growth through conventional drilling of the existing U.S. oil and gas fields. Two im-

portant questions are whether many opportunities remain to attain additional reserves through extension wells and infill drilling designed to produce mobile oil that would not have been **produced at previous levels of well spacing, and whether or not recently discovered fields, which are on the average smaller than their predecessors, will grow at historical rates. The former question remains controversial because of continuing disagreements about the actual level of heterogeneity existing in many of the Nation's oilfields.**

The Restructuring of the U.S. Oil Industry

Introduction

During the 1980s the U.S. oil industry has been undergoing a transition that has left virtually no segment of the industry unchanged. "Restructuring" is the overall term commonly used to describe the fundamental shifts in the size and composition of the domestic oil industry as a whole and the changes in internal organization and direction of individual companies. The current restructuring is reflected in the increasing consolidation of the industry and in widespread, often drastic adjustments in the operational and financial structures of individual companies and their petroleum investment strategies. This chapter describes some of the recent changes in the U.S. oil industry and the possible future implications for continued investment in domestic exploration and production.

Well before the 1986 oil price plunge, many of the major and independent oil companies embarked on ambitious operational and financial restructuring efforts in response to conditions creating increased uncertainty about oil's future profitability. Restructuring has taken varied forms including:

1. corporate mergers, acquisitions, and major asset sales and purchases;
2. operational and organizational changes to streamline business divisions and cut costs by combining or eliminating functions and, often, reducing the number of employees;
3. asset "redeployments" with companies expanding in operating segments and geographic areas where they perceive an advantage and eliminating less profitable operations through sales, asset writedowns, and liquidations;
4. adoption of financial strategies designed to enhance the market value of the company by increasing dividends, buying back stock, changing debt levels, or creating new equity investment opportunities (e. g., master limited partnerships);
5. increased use of joint ventures and other risk spreading arrangements for exploration and development projects; and in some extreme cases,
6. reorganization of assets and liabilities under the protection of bankruptcy proceedings.

There is general agreement that the current restructuring was prompted by prevailing conditions in the industry following the 1981 boom :20

1. There was a worldwide surplus in oil production capacity and excess capacity in refining and marketing operations as a result of the higher oil prices and industry expansion in the 1970s.
2. Oil consumption declined from 1979 to 1983 due to higher prices and conservation efforts and the recession; many industry forecasts predicted that annual growth in oil demand would be less than 1 percent per year through the year 2000.
3. Excess oil production capacity, reduced demand, and the breakdown of OPEC set oft a steady decline in oil prices in 1981. By 1983 there was a growing consensus that oil prices would remain low, and perhaps decline further, until at least the early 1990s.

[20] See, tor example, statement of T. Boone Pickens, jr., in *Legislation Attecting Oil Merger Proposals: Hearing on S. 2362a Bill to Amend the Mineral Lands Leasing Act of 1920 and for Other Purposes Before the Subcommittee. on Energy and Mineral Resources of the Senate Comm. on Energy and Natural Resources,* 98th Cong., 2d sess. 320 (1984), and supplementary material provided by Frank W. Bradley of Chevron Corp., *id.* at 536. (These hearings are hereafter referred to as *Legislation Attecting* 0)1 *Merger Proposals.*) *See* also *Impact of Oil Company Mergers: Report to the United States Senate, Prepared by the Majority Staff of the Senate Committee on Energy and Natural Resources,* S. Prt. 98-206, 98th Cong., 2d sess. (1984).

4. Many oil industry managers and investors were disappointed by the relatively high finding costs and the difficulty in finding and producing new domestic oil reserves, particularly in the light of the massive investments in exploration. There was a growing perception among some major oil companies that because of the past extensive onshore exploration in the United States, there were now fewer "good" U.S oil prospects remaining.

Some industry analysts would add to the foregoing conditions: concern over possible changes in Federal tax and oil and gas leasing policies, the pressures on companies from increasingly aggressive institutional investors demanding greater short-term returns from their holdings, and the fear of possible hostile takeover offers by corporate raiders.

Although changes in capital structures, mergers, acquisitions, liquidations, and bankruptcies are not unusual in the oil industry, recent years have seen a high level of these activities.[21] These widespread occurrences, coupled with the general conditions of overcapacity, reduced demand, and declining prices suggested to some observers that the domestic industry had entered a period of fundamental structural change before it began to experience the adverse effects of the plunge in world oil prices in 1986.[22] If the current restructuring is indeed symptomatic of the maturity of the U.S. oil industry, rather than the result of cyclical influences of world oil prices, this further suggests that a return to the slightly higher oil price levels preceding the price slide will not stem the eventual contraction of the industry and the decline in U.S. oil production. But there are others in the oil business who do not share the view that the U.S. industry is in inevitable decline. To them restructuring is desirable, but marks a normal and healthy evolution of the industry in response to changing conditions. They point out that the oil industry has been through similar periods of expansion and contraction in the past.

Restructuring has already had profound effects on the industry and on oil companies and their investment decisions. The success of their restructuring efforts and other strategies adopted by individual companies in response to low oil prices may well determine their economic viability in a new era of more volatile oil prices and stronger competition from foreign oil imports. The cumulative result may be oil's transformation into a smaller, more efficient industry with fewer companies and a different approach to business. But a smaller industry may not conduct as extensive or aggressive an exploration program to replace domestic reserves and this could increase U.S. reliance on foreign oil. Moreover, there is concern that the sharp increase in corporate indebtedness associated with recent mergers, acquisitions, and internal restructuring, coupled with declining earnings due to low oil prices, will mean sharply reduced expenditures for exploration and development in the short term as available cash flow is diverted to debt repayment. **In the long term, this trough in exploration expenditures could contribute to a decline in oil production.**

Conditions Causing Restructuring

World oil trends in the 1980s began to raise concerns about the future profitability of the domestic industry. Even as oil revenues soared in 1979-82, present and future earnings were being undermined by growing worldwide overcapacity in upstream and downstream operations, lower oil prices, declining demand, and changes in domestic tax policies. Additionally, the indus-

[21] Materials prepared for the Senate Banking Committee indicate that the number of mergers and acquisitions from 1983 to 1985 has been much higher than during the 1970s and has involved substantially more funds than ever before. According to *Mergers and Acquisitions*, over $122 billion was spent on completed transactions in 1984; oil and gas industry transactions probably were one third to one half of that total. See *Impact of Corporate Takeovers: Hearings on the Effects of Mergers on Management Practices, Cost, Availability of Credit, and the Long-Term Viability of American Industry Before the Subcommittee on Securities of the Senate Committee on Banking, Housing and Urban Affairs*, 99th Cong., 1st sess. 591-593 (1985). (Hereafter referred to as *Impact of Corporate Takeovers.)*

[22] U.S. Congress, Joint Economic Committee, "The U.S. Oil Industry in Transition: Causes, Implications, and Policy Responses," Comm. Print, 99th Cong., 2d sess., S. Prt. 99-154, May 20, 1986, at 9. This study by the Business School at Southern Methodist University concludes that current trends in the oil industry are characteristic of the mature phase of an industry life cycle: excess capacity, low growth, business failures and consolidation. The study compared the oil industry to other "distressed" mature domestic industries in transition such as steel, textiles, automobiles, and agriculture.

try **was becoming more vulnerable than in the past to rapid changes in oil prices as more and more oil was sold on the spot market or at spot-market-related prices.**

One clear **implication of these trends was that the majors could no longer** rely on rising prices and expanding product sales to assure future profits growth. The earnings of major U.S. oil companies did not reflect much of the initial oil price drop in 1981 to 1985 because most of the excess price over $20/bbl was taxed away by the windfall profits tax (WPT). The contribution to cash flow in dollars per barrel of crude oil equivalent for major U.S. companies after deducting the WPT fell only 1.6 percent between 1981 to 1984.[23] The independents, who generally carried a smaller WPT burden, however, were more seriously affected by the steady slide in oil prices. By 1985, many independents were already in financial difficulty because of the combined effects of lower oil prices and lower prices for natural gas. But as the price fell below $20/bbl in 1986, cash flows for both majors and independents were squeezed.

The prospects of slow demand growth and declining oil prices forced managements to reformulate their long-term business plans to decide how best to protect the future profitability of their companies. This reassessment accompanied the emergence of a management philosophy that places greater emphasis on financial performance and short-term returns to shareholders than on finding oil. With world oil industry conditions largely beyond their control, companies began to look inward for ways to cut costs and maintain profits and to reexamine the assumptions underlying their business strategies. Restructuring and a move away from continued heavy investment in domestic oil exploration have been two results.

Many integrated companies began to shift away from their past emphasis on maintaining a secure source of domestic reserves to supply their refining and marketing operations and to end the traditional priority given to recycling a high proportion of their production revenues back into exploration and development activities. The cutback in domestic exploration also marks a reevaluation of the potential for finding additional large oilfields in domestic frontier areas. Oil industry observers and company annual reports indicate that several companies appear to have altered their views on the economic viability of conducting a broad-based exploration and development program in the Lower 48 States at prices experienced in recent years. For example, Lodwrick C. Cook, the Chairman of the Board and Chief Executive Officer of ARCO, told his shareholders:

> [I]n the lower **48 we** intend to maximize productivity of existing fields and not try to replace production through further exploration in this declining region—though we will buy reserves when good opportunities come a long... Essentially we've shifted away from the high-risk, major-stakes emphasis of recent years and toward projects that can be expected to produce economic results more reliably. As the price of crude oil increases we can step up exploration again, although not on the large scale of recent years. **Results of the industry's late 1970s, early 1980s drilling boom weren't that encouraging—at any predictable price.** (Emphasis added.)[24]

Many majors and independents have not been able to replace their U.S. oil and gas production with new reserves despite heavy investment in domestic exploration, and the reserves they did find came at a high cost. For example, as shown in table 32, oil and gas reserve additions for many major oil companies, excluding purchased reserves, fell short of replacing annual production over the period 1979 to 1985. Even when purchased reserves are taken into account, many companies still did not replace depleted reserves. Over the same period, the U.S. industry replaced about 92 percent of its liquids production.

The poor success of some exploration efforts is also reflected in the relatively high implied finding costs incurred by some firms over the years 1979 to 1985. The average weighted implied finding cost for the major oil companies shown in table *32* was *$10.58* per equivalent barrel in 1979

[23] U.S. Department of Energy, Energy Information Administration, *Performance Profiles of Major Energy Producers 1984*, tables 21 and 22.

[24] Remarks of Chairman Lodwrick C. Cook at the 1986 annual shareholders meeting, reprinted in Atlantic Richfield Co. 1986 First Quarter Report, at 12, 15.

Table 32.—U.S. Oil and Gas Reserves Replacement as Percentage of Production, 1979-85, and Domestic Implied Finding Costs

	Production replacement excluding purchases and sales (weighted average 1979-85)[a]	Production replacement including purchases and sales (weighted average 1979-85)[b]	Implied finding costs $/Bbl oil equivalent (weighted average 1979-85)[c]
Major integrated oil companies:			
Amoco Corp.	109.0%	11 2,8%	$7.91
Arco	103.9	108,5	7.05
Shell Oil Co.	99.2	147.6	7.46
Chevron Corp.	81.4	169.3	9.48
Murphy Oil Co.	75.9	77.8	15.19
Exxon Corp.	75,6	77.2	9.93
Mobil Corp.	72.1	121.3	10.18
Phillips Petroleum Co.	69.5	98.3	9.53
Unocal Corp.	65.6	66.25	9.62
Sun Co.	58.1	79.3	11.05
Kerr-McGee Corp.	51.7	62.4	21.09
Standard 011 Corp.	22,2	23.0	26.61
Texaco, Inc.	Neg.	47.8	Neg.
Independent producing companies:			
Noble Affiliates,	150.7	151.6	9.04
Mitchell Energy & Development Co. .,	1423	146.7	1041
Pogo Producing Co.	93.6	93.8	1417
Sabine Corp.	88.5	1 17.4d	1204
Pennzoil Co,	86.4	102.3	8.91
Louisiana Land & Exploration Co. ...	39.8	40.7[e]	21.91

[a]Replacement includes reserves added through discoveries. extensions Improved recovery and revisions of previous estimates

[b]Replacement includes reserves added through discoveries, extensions, improved recovery and revisions Of previous t? stimates plus the effects of reserves purchases and sales

[c]Finding cost excludes proven reserves purchases except where property acquisition costs do not break out proven and unproven acreage

[d]Excludes reserves distributed to the Sabine Royalty Trust

[e]Excludes reserves distributed to the LL&E Royalty Trust

SOURCE Office of Technology Assessment from Donald F Textor Todd L Bergman Cristina Tiscareno Finding Cost and Reserve Replacement Results 1979-1985 Goldman Sachs Research April 1986

to 1985. There was a wide range in reported finding costs among these companies, from $7 to over $26/bbl. Several companies had extremely poor results in their domestic exploration programs with implied finding costs well above the $5 to $9/bbl average purchase cost of proven reserves over the same period .25

High finding costs translate into a low profit margin per barrel (or even a loss) if prices do not rise. The declining profitability of newly added reserves was becoming apparent even at prices over $20/bbl. This trend is reflected in several commonly used indirect measures of the profitability of exploration and production activities:

- **Discounted Future Net Cash** Flows.—A measure of the present value of all proven oil and gas reserves derived by applying year-end oil and gas prices to estimated future production to yield expected production revenues flows, then subtracting estimated future production and development costs and future income taxes, and discounting the resulting annual future net cash flows by an annual discount rate (usually 10 percent).
- **Present Values Added Through Exploration and Development.—The present value of new reserves added as a result of exploration and development activities in a given year. This measure is calculated** for newly discovered reserves in the same manner as discounted future net cash flows above.
- **Value-Added Ratios.–Two** measures of the returns on exploration and development investments. The **value-added ratio for exploration and development** is expressed by comparing the present value of new reserves added by exploration and development activities with the costs incurred to acquire, explore and develop the reserves. The **value--added ratio for all sources** compares the present values of reserves added through ex-

[25]Arthur Andersen & Co., *Oil & Gas Reserves Disclosures: 1981 to1985 Survey of 375 Public Companies, s-46 (1986).* and estimates provided by Strevig & Associates in ''Prices for Reserves Purchases on the Upswing, " *Oil* & Gas *Journal,* Feb. 16, 1987, at 46.

ploration, revisions, and reserves purchases (less sales) to the total costs incurred to obtain the reserves including amounts paid to buy proven properties.

The above measures are calculated assuming that all future production is at year-end prices and lifting costs; the year-end prices are not escalated u n less the reserves are covered by a contract provision requiring such an adjustment. The measures are recalculated each year to reflect changes in prices and costs and are required by the Securities and Exchange Commission (SEC) to be included i n many oil company annual reports. Although companies generally disclaim the accuracy of these measures as indicators of future E&P profitability, the measures do allow for comparison between companies and for identification of industry trends.

According to an Arthur Andersen & Co. analysis, shown in table 33, projected future net cash flows for 375 of the largest publicly held oil and gas companies remained fairly steady in 1981 to 1984, with the initial price decline offset somewhat by lower lifting costs and taxes.[26] In 1985 future net cash flows dropped 8 percent at year-end prices of about $25/bbl. At mid-1986 prices of $15/bbl and less, the future cash flows from proven reserves will likely be substantially less. Some analysts believe that the increases in reserve values experienced as a result of the price increase in 1979 to 1981 will probably be wiped out by the 1986 price fall.

[26]Arthur Andersen & Co., *Oil and Gas Reserves Disclosures: 1981-1985 Survey of 37.5 Public Companies*, at *s-37* to *s-38*.

Moreover, the values of new reserves added through exploration and development by major oil companies worldwide declined between 1981 to 1985 as shown in table 34. The Arthur Andersen study attributed the decline to the fact that much of the majors' new reserves came from costly improved recovery techniques and exploration in high cost remote areas .27 The value added on a per-equivalent barrel basis for the 375 companies analyzed in the study has also declined since 1982. The majors generally posted the lowest added value per barrel from exploration. The profitability of these low value reserves is expected to be highly sensitive to price changes.

The troubling outlook for the profitability of exploration investments is indicated when the values of reserves added are compared to the costs of discovering and developing the new reserves. As shown in table 35, since 1981, companies have spent more looking for oil and gas (the "costs incurred for exploration and development") than the present value of the reserves found. Only in 1985 did new reserves values exceed costs incurred, primarily because the costs declined more than the net decrease in the value of reserves added. The value added from all new reserve sources, including exploration, development, revisions and net purchases and sales, however, significantly exceeded the related costs incurred in the same period.

[27]An additional reason for the low present va l u es Of the new reserves posted by the majors is that many of these discoveries have long lead times before commercial production and cash inflows begin, In contrast, many of the non-majors' reserve additions have relatively short leadti mes before prod uction and income start,

Table 33.—Valuations of Proved Reserves

	Discounted future net cash flows[a] (billions)									
	In the United States					Worldwide				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Majors	$109.2	$118.9	$115.0	$120.9	$122.5	$167.4	$172.8	$169.9	$176.1	$181.1
Independent	13.8	14.8	14.8	14.7	13.2				17.2	15.0
Pipeline/utility	7.3	7.3	6.8	6.3	5.6	9.1	9.1	8.6	8.8	7.6
Diversified	23.1	25.6	25,5	26,3	25.7	38.9	40.9	39.1	40.7	41.1
Total	$153.4	$166.3	$162.1	$168.2	$167.0	$232.3	$240.0	$234.7	$242.8	$244.8

[a]Based on SFAS No, 69 criteria.

SOURCE Arthur Andersen & Co "Oil & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies, " 1986.

Table 34.—Values Added Through Exploration and Development—Worldwide

	Present value of reserves added[a] (millions)					Per equivalent barrel				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Majors.	$15,447	$17,926	$16,760	$18,948	$22,071	$5.83	$5.24	$5.65	$7.61	$ 7.39
Independents	2,007	2,672	2,362	3,221	3,447	8.38	10.71	10.41	11.67	11.38
Pipeline/utility	1,850	2,009	1,576	1,597	1,583	8.61	9.91	10.37	5.66[b]	9.40
Diversified	6,677	7,927	5,988	7,712	8,262	8.44	9.08	8.65	10.31	10.05
Total/weighted averages	$25,981	$30,534	$26,686	$31,478	$35,363	$6.67	$6.43	$6.61	$8.29	$8.26

[a]Extensions and discoveries plus improved recoveries.
[b]Includes the effects of one company's downward quantity revisions in 1981, subsequently reflected as quantity additions in 1982.

SOURCE' Arthur Andersen & Co., "Oil & Gas Reserves Disclosures: 1981-85 Survey of 375 Public Companies, " 1988.

Table 35.—Value Added Ratios-Worldwide

Exploration and development	Five-year average	1985	1984	1983	1982	1981
Majors . . . . i	91 "/0	100%	780/o	920/o	890/o	95 "/0
Independents	99	92	133	106	92	84
Pipeline/utility	87	102	101	90	73[a]	71[a]
Diversified	103	119	130	100	91	87
Weighted average ., ...	93 "/0	103 "/0	890/o	94 "/0	890/o	920/o
Ail sources						
Majors	144"/0[b]	177"/0[b]	145"/0	1300/0	1lOO/o	1620/o
Independents	127	96	147	116	127	141
Pipeline/utility	132	131	152	140	183[a]	51a
Diversified	145	125	184	123	115	176
Weighted average	143%[b]	158%[b]	150%	1280/o	1160/0	1590/0

[a]Principally reflects one company's downward revisions in 1981, subsequently reflected as upward revisions in 1982.
[b]Includes the effect of downward revisions of certain Alaskan gas reserves in 1985. Excluding such revisions, the majors' and 5-year averages would be 181 % and 161 % in 1985, respectively, and unchanged for the 5 years.

SOURCE" Arthur Andersen & Co., "Oil & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies, " 1986

These trends posed two concerns for the oil industry:

1. that lower future cash flows would mean less internal capital available to replace depleted reserves; and
2. that under existing price expectations, domestic exploration was proving to be a disappointing and costly means of replacing reserves.

These prospects led some companies to conclude that their limited exploration funds should be spent elsewhere—e.g., more intensive development drilling, more foreign exploration, or acquiring other companies or buying proven properties, or investing internally by buying back shares or boosting dividends.

Mergers and Acquisitions

The recent wave of mergers and acquisitions has reordered the domestic industry and thinned the ranks of majors and independents alike. The sheer size of some of the transactions involved and the controversial tactics of corporate raiders and target company managers have attracted headlines and raised concerns over the potentially adverse effects of "merger mania" on the domestic oil industry. Among the concerns were the effects on competition in the industry and the impacts on capital spending and exploration of the massive increase in merger-related debt.

During the period 1979 to 1986 over $75 billion was spent on the acquisition of publicly traded oil and gas companies. Table 36 lists some of the largest transactions involving oil producers.[28] Many oil companies concentrated on ac-

[28]This list is not inclusive and does not, for example include oil company acquisitions of coal companies and nonenergy companies during the same period. Among the more notable of these transactions were Standard 011's $2 billion purchase of Kennecott Corp. in 1982 and Gulf Oil Co.'s purchase of Kemmerer Coal Co., in 1981. Large-scale mergers in the mid-1980s have not been limited to 011 companies. Other multi-billion dollar transactions Include IBM's purchase of Rolm, Nestle's acquisition of Carnation, General Electric's takeover of RCA, and Capital Cities Communications' buyout of ABC. See *Impact of Corporate Takeovers, supra* note 2.

Table 36.—Mergers and Acquisitions in the U.S. Oil Industry

Year	Acquiring company	Target	Millions of dollars	Remarks
	Broken Hill Proprietary Ltd.	Energy Reserves Group	n.a	
	Houston Natural Gas	Florida Exploration	n.a	
	Mobil Oil Corp.	Vickers Energy	n.a	From Esmark
1979	Getty Oil Co.	Reserve Oil and Gas	620,0	
1979	Mobil Oil Corp.	General Crude Oil	792.0	From International Paper
1979	Shell Oil Corp.	Belridge Oil	3,660.0	
1980	Mobil Oil Corp	Trans Ocean Oil	715.0	
1980	The Sun Co., Inc.	Texas Pacific Oil & Gas	2,300.0	Properties acquisition only
1981	E.I. du Pent de Nemours & Co.	Conoco, Inc.	7,800.0	
1981	Occidental Petroleum Corp.	Crestmont Oil & Gas	82.3	
1981	Tenneco	Houston Oil & Minerals	1,650.0	Stock for stock
1982	Ashland Oil Co,	The Tresler Oil Co.	90.0	
1982	Ashland Oil Co	Scurlock Oil Co,	13.0	
1982	Occidental Petroleum Corp.	Cities Service	3,984.0	Cash plus stock
1982	U.S. Steel	Marathon Oil	5,950.0	
1983	Burlington Northern	El Paso Natural Gas	1,300.0	
1983	CSX Corp.	Texas Gas Resources	1,100.0	
1983	Diamond.	Shamrock Natomas.	1,500.0	
1983	Freeport McMoRan	Stone Exploration	112.0	
1983	Internorth (Enron)	Belco Petroleum	800.0	
1983	Phillips Petroleum	General American Oil	1,100.0	
1984	Chevron Corp.	Gulf Oil Corp.	13,300.0	
1984	Damson Oil	Dorchester Gas	400.0	
1984	Freeport McMoRan	Midlands Energy.	294.0	
1984	Mobil 011 Corp.	Superior Oil.	5,720.0	
1984	Phillips Petroleum	Aminoil USA,	1,600.0	From R.J. Reynolds
1984	Texaco, Inc.	Getty Oil.	10,200.0	
1984	The Sun Co , Inc.	Exeter Oil	75.0	
1984	U.S. Steel	Husky Oil USA	488,0	Asset acquisition
1985	BHP Petroleum Americas	Montsanto Oil	575.0	From Monsanto
1985	Burlington Northern	Southland Royalty		
1985	Coastal Corp.	American Natural Resources	2,400.0	
1985	Enron (Internorth)	Houston Natural Gas	2,200.0	
1985	Freeport McMoRan	Pel-Tex Oil	70.5	Assets acquisition only
1985	Midcon Corp.	United Energy Resources	1,200.0	
1985	Union Texas Petroleum	Union Texas Petroleum	n.a	LBO from Allied-Signal Corp.
1986	Freeport McMoRan	Petro-Lewis & American Royalty Trust:	440.0	jointly with Kidder Peabody
1986	Louisiana Land & Exploration Co.	Inexco Oil	470.0	
1986	Mesa Limited Partners	Pioneer Production Co.		Mesa Units and Debt
1986	Occidental Petroleum Corp.	Midcon Corp.	1,575.0	Cash for 53% plus Oxy stock
1986	U.S. Steel	Texas Oil and Gas	3,700.0	

n.a = not available

SOURCES: Oil and *Gas Journal,* Arthur Andersen & Co., and Congressional Research Service report, "Mergers and Acquisitions by Twenty Major Petroleum Companies January 1981 through February 1984."

quiring other companies in their core energy and chemical businesses. This pattern differs from the 1970s when many energy companies sought to diversify into other areas to cushion themselves from the uncertainties of world oil markets. For example, ARCO bought Anaconda Minerals, a major copper producer, and Mobil bought Montgomery Ward Department Stores. For **many major oil companies, the diversifications have** been disappointing and now, as part of restructuring programs, they are selling, spinning off, or liquidating these subsidiaries to return to their core energy and chemical businesses.

The largest of the mergers were in 1984 as Chevron bought Gulf, Mobil bought Superior, and Texaco acquired Getty. As the mergers and acquisitions trend continued in 1985 to 1986, the transactions frequently involved the absorption of a smaller ailing company into a larger, more financial sound company. (For example, Loui**siana Land & Exploration's acquisition of Inexco** Oil, and Freeport-McMoRan's bid for Petro-Lewis.) Major asset purchases have also continued. Some larger independents, such as Murphy Oil and Noble Affiliates, have told their shareholders that they are aggressively seeking acquisitions as a means of adding reserves at low cost. Takeovers and consolidations can be expected to continue as lower prices undercut the financial viability of many independent producers.

The recent mergers and acquisitions raised a number of major criticisms:

1. that massive merger-related borrowing by oil companies could crowd out other industries in capital markets;
2. that acquisitions would divert funds from exploration and development and other capital investment;
3. that the mergers eliminate viable competitors and contribute to the harmful consolidation of the industry;
4. that companies that acquired new reserves would be less likely to maintain an aggressive exploration program to replace production; and
5. that the massive new long-term debt assumed by some companies to successfully fend off hostile tender offers would seriously impair their ability to fund future exploration activities.

These concerns are countered with the arguments offered by those who strenuously defended all or some of the merger activities:

1. merger-related borrowing by oil companies was only a small portion of total loans outstanding and did not deprive other borrowers of credit;
2. in the past, oil industry merger-related loans were paid down within a few years out of asset sales and cash flow;
3. the funds paid for the acquired company did not disappear from the economy, but were returned to shareholders who could then reinvest them;
4. the merged firms will have to continue and even expand exploration programs to support the combined production levels;
5. investments in exploration are determined by expectations of future oil prices and profitability and are not influenced by the separate and independent considerations pertaining to mergers and acquisitions;
6. mergers and acquisitions are the marketplace's natural mechanisms for weeding out inefficient companies, moving assets to more efficient operators, and providing opportunities for new entrants into the industry and for expansion of existing firms;
7. newly merged firms are stronger competitors, both nationally and internationally; and finally
8. even unsuccessful takeovers contribute to the necessary restructuring of the industry because, to avert takeovers, target managements are forced to make changes in capital and operating structures that enhance shareholder values.

Reasons for Oil Industry Merger Mania

There have been many explanations offered in congressional hearings for the wave of ''merger mania" that struck the oil industry; some are summarized below. Many of the differences in viewpoint are not factual disputes, but represent contrasting values, policies, and theories. These reasons can be divided into two categories: those that relate to mergers and acquisitions in general, and those that reflect the special circumstances of the U.S. oil industry in the 1980s.

Among the general conditions resulting in merger and acquisition activity are:

- Mergers and acquisitions are the marketplace's natural remedies for inefficient corporate management and are the means for assets to flow to more productive use by stronger, more efficient companies. To the extent that the market value of oil companies is less than their book value, this reflects the stock market's correct assessment of their performance.
- Even a profitable company with competent managers can become a takeover target, if another company believes that the target's assets might be more valuable and profitable in its hands or if the target has some special expertise or capabilities that cannot easily be reproduced. The purchaser can thus afford to offer a premium over the market price to acquire the target to realize an increase in value of the assets under different management or as a means of entry into a new market or industry.

- Federal income tax benefits made corporate acquisitions attractive investments because of the deductibility of interest payments on merger-related debt, the stepped up basis in the acquired assets, and accelerated depreciation.
- Some recent takeover attempts were profitable for some companies and their financial backers, even if they did not succeed, for several reasons. To avert a threatened takeover the defending management sometimes brought the hostile offerors' shares at a substantial premium over the original purchase price. For example, Mesa Petroleum netted $214 million **on its** unsuccessful offer for Gulf, $4 l million from its offer for Phillips Petroleum, and an additional $83 million from its Unocal offer before the sale of another 14.6 million shares of Unocal it still held in 1986.[29] In other circumstances, the takeover threat caused the target management to initiate programs to return greater value to all shareholders, which the takeover group then shared. Once a takeover attempt was announced, the target company's stock often rose. Because securities laws only require public notification when an individual or company acquires more than a threshold percent, the takeover group could "accumulate" a substantial position in the target's stock on the open market before the announcement and then gain from selling the stock at a higher post-announcement price without ever completing the takeover bid.[30] Some critics contend that raiders and their investment bankers put companies "in play" by announcing a takeover bid without ever intending to complete the bid just to profit from "greenmail" offered by the target companies and from the runup in the stock's price.

Conditions in the oil industry in the 1980s also tended to favor mergers and acquisitions activity:

- The mergers and acquisitions could be seen as part of a larger trend in the restructuring of the oil industry. Mergers and acquisitions are symptomatic of the structure of a "mature" or "declining" industry. The consolidation reflects the expectation that the mature industry has only modest growth prospects and may have entered a period of inevitably declining production as remaining reserves are depleted.[31]
- The high debt levels and interest rates assumed by many independent oil companies to expand rapidly during the 1979-82 boom placed them in severe financial difficulty when oil prices began to decline. In order to survive, many of these businesses sought buyouts or mergers with other, stronger companies .32
- Some recent takeover attempts were profitable for some companies and their financial backers, even if they did not succeed, for several reasons. To avert a threatened take-value as the underlying oil and gas reserves after oil prices tripled in 1979 to 1980. Oil company stocks sold for less than their per-share appraised value and for considerably less than the per-share breakup value. Several stocks sold for less than the per share book value of the company's assets.[33] This disparity made the companies attractive takeover targets. Corporate raiders, backed

[29] Mesa petroleum, *Annual Report 1985,* p. 24.

[30] Takeover offers can be annou need "contingent on financing." The target and offeror stock prices often rise following the announcement and the offeror could later withdraw the offer without ever purchasing any tendered stock and still benefit from the increase in value of the shares already held. In addition to gains on the sale of stock, the backers of a takeover group often receive commitment tees, commissions and legal fees.

[31] See Joint Economic Committee Study, *supra note 3.*

[32] See *testimony* of Jon Rex Jones for the Independent Petroleum Association of America in *Legislation Affecting Oil Merger Proposals, supra* note 1, at *321,*

[33] According to testimony given a House Comm ittee, i n March 1984 the stocks of five large integrated international oil companies, Exxon, Gulf, Mobil, Standard of California (SoCal) and Texaco were selling at an average 43.9 percent of their J.S.Herold appraised value. Of the group, Gulf, which was later acquired by SoCal, was selling at 57.2 percent of it's appraised value, the highest of the group. See testimony of Mark Gilman, in *Oil Industry Mergers:* Hearings on H.R. 5153, H.R. 5175, and H.R. 5452, Bills to Amend the Federal Trade Commission Act to Require a Study of Mergers, Acquisitions, and Joint Ventures in the Auto and 011 Industries, and for Other Purposes Before the Subcommittee on Fossil and Synthetic Fuels and the Subcommittee on Commerce, Transportation, and Tourism of the House Committee on Energy and Corn merce, 98th Cong., 2d sess. 250 (1984). (Hereafter, *Oil Industry Mergers.) See* also material submitted by T. Boone Pickens on comparative stock values and book values of major oil companies appended to testimony of Claude Brinegar of Unocal in *Impact of Corporate Takeovers, supra* note 2, at 82, 89-90. In his testimony Brinegar noted that the stocks of three companies that had previously restructured were selling at a lower percent of appraised value than companies that had not.

by aggressive institutional investors, Wall Street investment bankers and arbitrageurs, and often financed by "junk bonds," put increasing pressure on oil companies to improve their return to investors or to become takeover targets.

- Acquisitions also were a more attractive investment alternative than some high risk exploration ventures for the huge revenues generated from oil production during the period of higher prices. Acquisitions also offered a quick and effective means of replacing reserves depleted through production. Some companies believed it was more financially attractive and less risky to "drill for oil on Wall Street" (by buying other companies for their proven reserves) than to continue to invest in risky exploration activities. Buying a company also offered the prospects of an immediate cash infusion from its producing reserves and from the sale of unwanted assets. In contrast, it is often years before there is any return from investments in long-term exploration and development projects.[34]

Effects of Mergers and Acquisitions

Mergers and acquisitions are claimed to be beneficial overall for stockholders and economy. Among the positive effects generally cited are: improved efficiency and lower costs for the merged entity, lower costs to consumers, and increased returns on investments in the stock of publicly held companies either from the premium over market value offered in the takeover, or from the correction in discounted stock prices.[35]

Another claimed benefit of mergers among major oil companies is that the larger combined companies will be stronger technically and financially and, thus, better able to sustain the increasing costs and risks of developing reserves in frontier areas and to compete with large foreign oil companies, often supported by their governments, in acquiring and developing concessions abroad.[36] Except for the gains realized on the sale of stock in the acquired companies, it is still too early to determine whether the recent mergers will in fact have these effects over the long term.

At the same time that mergers may prove beneficial to individual companies there remains the possibility that they could contribute to a net reduction in domestic petroleum production in the long term. The most obvious short-term results of the mergers have been an increased consolidation of the oil industry, a significant increase in long-term debt, and an apparent reduction in capital spending on exploration and production. For many industry observers, fewer companies and less exploration spending means fewer wells drilled, fewer reserves discovered, and eventually lower oil production.

OTA has reviewed the financial performance of 26 major and independent oil companies to assess the impacts of mergers and other restructuring changes in recent years. Table 37 presents aggregate information on these companies from their annual reports in 1983 to 1985. The companies are also subdivided into those that were involved in major corporate acquisitions (both successful and unsuccessful) in 1982 to 1986 and those that were not.[37] They include two groups, 14 major integrated oil companies, and 12 smaller independent oil companies. Measuring the impacts of mergers on these companies is complicated by the fact that most of the companies have ongoing restructuring programs that are intended to have some of the same results as some mergers. Nevertheless, OTA found some clear differences between companies involved in takeovers and other companies. There were also clear differences in expenditures for combined

[34] See responses of Mobil Oil Co. to Committee questions in *Legislation Affecting Oil Merger Proposals, supra* note 1, at *638.*

[35] Efficiency gains are attributed to: i) increased economies of scale due to the larger size of the new entity; ii) marriage of complementary factors such as the combination of a reserves-rich firm with a reserves-poor company with extensive refining, marketing and petrochemical operations; iii) rationalization of production facilities by, for example, maintaining the most efficient facilities of the combined operations and eliminating others; iv) replacement of weak management; and v) economical technology transfer. See Testimony of Joseph j. Wright, Office of Management and Budget, in *Impact of Corporate Takeovers, supra* note *2,* at 610-612. See also statement of Morgan Stanley & Co., *Inc. in Legislation Affecting Merger Proposals, supra* note 1, at 516, and testimony of Professor Edward J. Mitchell, Graduate School of Business, University of Michigan in *Oil Industry Mergers, supra* note 13, at 359-60.

[36] Supplementary material submitted by Standard Oil Co. of California in *Legislation Affecting Oil Merger Proposals, supra* note 1, at *540.*

[37] For *Purposes* of this study "major" acquisitions are those over *$400* million.

Table 37.—Financial Performance of a Group of Oil Companies, 1983-85 (millions of dollars, except percentages and ratios)

	Non-takeovers			All takeovers			Successful takeovers			Successful defenses			All companies in group		
	1985	1984	1983	1985	1984	1983	1985	984	1983	1985	1984	1983	1985	1984	1983
Large integrated oil companies:															
Revenues	209,525	214,809	211,148	200,717	203,830	179,027	173,276	176,546	153,072	27,441	27,284	25,955	410,242	418,639	390,175
Pretax net income	18,614	24,448	23,371	16,802	16,212	14,770	14,186	12,855	11,352	2,616	3,357	3,418	35,416	40,660	38,141
Earnings	10,012	12,582	12,668	4,654	5,429	6,183	3,911	3,919	4,836	743	1,510	1,347	14,666	18,011	18,851
Cash flow	30,585	31,242	28,724	21,633	19,991	16,441	17,668	15,730	12,626	3,965	4,261	3,815	52,218	51,233	45,165
Internal cash flow	32,097	34,947	33,319	29,704	26,973	21,319	24,755	21,428	15,983	4,949	5,545	5,336	61,801	61,920	54,638
Total assets	192,855	183,174	180,741	159,390	159,827	126,397	134,548	132,669	104,081	24,842	27,158	22,316	352,245	343,001	307,138
Total shareholders equity	79,529	83,676	75,188	59,864	68,794	58,032	56,590	56,476	46,703	3,274	12,318	11,329	139,393	152,470	133,220
Total long-term debt	27,811	24,941	15,489	37,105	43,348	15,149	28,475	39,387	11,767	8,630	3,961	3,382	64,916	68,289	30,638
New long-term debt	6,802	3,508	3,689	15,947	27,990	4,012	5,565	26,741	3,478	10,382	1,249	534	22,749	31,498	7,701
Total debt/total capitalization	0.26	0.23	0.17	0.38	0.39	0.21	0.33	0.41	0.20	0.72	0.24	0.23	0.32	0.31	0.19
Debt/equity	0.35	0.30	0.21	0.62	0.63	0.26	0.50	0.70	0.25	2.64	0.32	0.30	0.47	0.45	0.23
Where the money went:															
Interest expense	3,428	3,003	3,069	5,824	4,475	2,089	4,504	4,029	1,719	1,320	446	370	9,252	7,478	5,158
Percent of earnings before interest and taxes	16	11	12	26	22	12	24	24	13	34	12	10	21	16	12
Dividends	6,291	6,332	6,020	3,898	3,774	3,665	3,187	3,238	3,154	711	536	511	10,189	0,106	9,385
Percent of cash flow from continuing operations	21	20	21	18	19	22	18	21	25	18	13	13	20	20	21
Repurchase of stock	7,322	5,379	874	11,316	1,533	253	2,166	1,533	253	9,150	0	0	18,638	6,912	1,127
Percent of internal cash flow	23	15	3	38	6	1	9	7	2	185	0	0	30	11	2
Total capital spending	25,899	23,901	20,622	12,686	15,322	3,182	0,099	12,009	10,461	2,587	3,313	2,721	38,585	39,223	33,804
Percent of internal cash flow	81	68	62	43	57	62	41	56	65	52	60	51	62	63	62
Percent of change	8	16	—	−17	16	—	−16	15	—	−22	22	—	−2	16	—
Capital spending for E&P (mostly U.S.)	16,852	16,333	13,487	7,542	8,379	7,134	5,776	6,470	5,403	1,766	1,909	1,731	24,394	24,712	20,621
Percent of internal cash flow	53	47	40	25	31	33	23	30	34	36	34	32	39	40	38
Percent of change	3	21	—	−10	17	—	−11	20	—	−7	10	—	−1	20	—
Repayment of long-term debt	4,195	3,527	4,267	18,522	4,725	4,054	6,135	4,198	3,869	2,387	527	185	22,717	8,252	8,321
Percent of internal cash flow	13	10	13	62	18	19	65	20	24	48	10	3	37	13	15

(continued on next page)

Table 37.—Financial Performance of a Group of Oil Companies, 1983-85 (millions of dollars, except percentages and ratios)—Continued

	Non-takeovers			akeovers			Total for group		
	985	1984	1983	1985	1984	1983	1985	1984	1983
Smaller independent oil companies:									
Revenues	8,995	9,459	8,910	9,435	8,663	8,164	18,430	18,122	17,074
Pretax net income	1,159	1,676	1,714	428	993	707	1,587	2,669	2,420
Earnings	325	768	792	432	561	407	757	1,329	1,199
Cash flow	2,780	2,647	2,345	1,314	1,178	1,196	4,094	3,825	3,540
Internal cash flow	2,297	2,959	2,847	1,180	1,468	1,357	3,477	4,427	4,204
Total assets	15,482	5,259	14,458	13,016	10,735	8,790	28,498	25,994	23,248
Total shareholders equity	5,628	5,838	5,841	2,325	2,601	2,444	7,954	8,439	8,285
Total long-term debt	3,965	3,599	2,852	5,715	4,144	2,862	9,680	7,743	5,714
New long-term debt	1,151	470	274	2,355	2,537	1,075	3,506	3,007	1,349
Total debt/total capitalization	0.41	0.38	0.35	0.71	0.61	0.54	0.55	0.48	0.42
Debt/equity	0.70	0.62	0.49	2.46	1.59	1.17	1.22	0.92	0.69
Where the money went:									
Interest expense	405	392	393	630	358	222	1,036	750	615
Percent of earnings before interest and taxes	26	19	19	60	27	24	39	22	20
Dividends	624	326	269	130	123	117	754	449	386
Percent of cash flow from continuing operations	22	12	11	10	10	10	18	12	11
Repurchase of stock	289	287	15	261	695	298	550	982	313
Percent of internal cash flow	13	10	1	22	47	22	16	22	7
Total capital spending	2,495	2,279	1,831	907	690	851	3,402	2,968	2,681
Percent of internal cash flow	109	77	64	77	47	63	98	67	64
Percent of change	9	24	—	32	-19	—	15	11	—
Capital spending for E&P (mostly U.S.)	1,787	1,581	1,461	512	492	639	2,298	2,073	2,100
Percent of internal cash flow	78	53	51	43	33	47	66	47	50
Percent of change	13	8	—	4	-23	—	11	-1	—
Repayment of long-term debt	813	347	371	1,296	786	737	2,109	1,133	1,108
Percent of internal cash flow	35	12	13	110	54	54	61	26	26

companies before and after the mergers. For example, as discussed later, OTA found that the large post-merger firms spent a smaller portion of available cash flow for exploration and other capital expenditures and devoted a higher level **of cash flow for debt reduction than did firms that were not involved** in acquisitions.

Several of the large company mergers have resulted in a retrenchment and contraction of resulting entities into something significantly less than the sum of the combined pre-merger companies with fewer employees, fewer total reserves, and less total production than before. While some downsizing reflects efficiency gains in the reduction of redundant overhead, other shrinkages are the results of asset sales and additional cost-cutting so that cash can be redirected to paying down debt.

There has also been a redistribution of oil and gas assets through post-merger asset sales. This may result in properties being transferred to new owners who can make more efficient and profitable use of them. Some major oil companies are selling off less profitable wells **in smaller producing oilfields with high overhead** levels. These properties could be attractive to other companies with extensive holdings in the same field that could benefit from economies of scale, or to independent producing companies with lower overhead. Some new owners have made or announced planned investments to expand production in their newly acquired properties. These asset sales are also coming at a time when the price for proven properties is much lower than it has been, so that companies buying reserves can often do so for much less than average finding costs.

Mergers and the Consolidation of the Oil Industry

The new combinations arising from the recent mergers reordered the rankings of the major oil companies. Table 38 **shows** the top 20 petroleum companies ranked by assets, liquids reserves, and liquids production **in** 1980 and 1985. By 1985, 9 of the top 30 oil companies in 1980 had been acquired. The primary changes in the rankings are the disappearance of some **"second tier"** independent integrated companies and the elevation of smaller companies into the ranks of **the** majors. As shown **in table** 39, **the** relative holdings of the top 8 firms have increased through the Gulf-Chevron merger and the absorption of several of the larger independents, Getty, Marathon, and Superior.[38] At the same time the concentration levels of the largest 20 oil companies have declined relative to the rest of the industry.

Consolidation has also been significant among the independents. Mergers and acquisitions, as well as bankruptcies, dissolutions, and liquidations have also contributed to a thinning and consolidation in the ranks of the independents. According to the 0il *and Gas Journal* annual reports on the 400 largest publicly held oil and gas producers, the year-end value of assets needed to place on its list dropped from $2.37 million in 1983 to $276,000 in 1984, to $179,000 in 1985.39 Among the smaller public and private independents, there has also been a severe shrinkage which has **been estimated at about** 25 to 30 percent of the independent exploration and production companies. While detailed information on the disappearance of the independents is not readily available, the estimated number of independents, as presented in testimony on behalf of the Independent Petroleum Association of America (IPAA), declined from over 15,000 **in 1984 to about 12,000 in mid-1986.**[40] **Some believe that the majors could be a more dominant influence** in domestic exploration and production than before 1980 as a result of the consolidation among the larger companies and the disappearance of so many independent operators.

Some industry observers believe that the contraction of the majors could create more opportunities for independents in some niches. With smaller exploration staffs and less money to spend on drilling, the majors may be willing to do more

[38] The table does not fully reflect the acquisitions announced in 1986; when these transactions are taken into account they will further reflect this trend.

[39] 82 *Oil & Gas Journal* 103, Sept. 10, 1984; 83 *Oil & Gas Journal* *89,* Sept. 10, 1985; 84 *01/ & Gas Journal 55,* Sept. 8, 1986.

[40] See testimony of Raymond H, H efner, for the IPAA in *Hearings on the Domestic and International Petroleum* Situation and the *Implications of Fees on Imported Oil Before the Senate Comm. on Energy and Natural Resources,* 99th Cong., 2d sess. 196, 225 (1 986). See also, testimony of Jon Rex Jones for the IPAA in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 315.

Table 38.–Comparison of 20 Largest U.S. Oil Companies, 1980 and 1985

Top 20, 1985 Rank company	Total assets ($ billions)	Top 20, 1980 Rank company	Total assets ($ billions)
1 Exxon Corp.	69.16	1 Exxon Corp.	56.58
2 Mobil Corp.	41.75	2 Mobil Corp.	32.71
3 Chevron Corp.	38.90	3 Texaco, Inc.	26.43
4 Texaco, Inc.	37.70	4 Standard of California (Chevron)	22.16
5 Shell 0il Co.	26.53	5 Standard Oil (Indiana)	20.17
6 Amoco Corp.	25.20	6 Gulf Oil Corp.	18.64
7 Tenneco, Inc.	20.44	7 Shell Oil Co..	17.62
8 Atlantic Richfield Co.	20.28	8 Atlantic Richfield Co.	16.60
9 Standard Oil Co.	18.33	9 Tenneco, Inc.	13.85
IO Phillips Petroleum Co.	14.05	10 Standard Oil (Ohio)	12.08
11 Sun Co., Inc.	12.92	11 Conoco Corp...	11.04
12 Occidental Petroleum Corp.	11.59	12 Sun Co., Inc.	10.96
13 Unocal Corp.	10.80	13 Phillips Petroleum Co.	9.84
14 Marathon Oil Co.	10.07	14 Getty Oil	8.27
15 Conoco Corp.	9.90	15 Union Oil of California.	6.77
16 Enron Corp.	9.89	16 Occidental Petroleum Corp.	6.63
17 Coastal Corp.	8.29	17 Amerada Hess Corp.	5.90
18 Amerada Hess Corp.	6.22	18 Cities Service.	5.36
19 Columbia Gas System, Inc.	5.84	19 Marathon Oil Co.	5.04
20 Midcon Corp.	5.81	20 Coastal Corp.	4.11

NOTE: Excludes mergers after Dec. 31, 1985

SOURCES *Oil and Gas Journal,* Sept *5, 1988, Fortune Magazine, "500* Largest Industrial Corporations," 1980 data, published May 4, 1981, at 322

Table 39.—Comparison of Historical Concentration in the U.S. Oil Industry (percent of U.S. total)

Concentration ratio-U.S. net crude oil, condensate, and natural gas liquids production									
	1955	1960	1965	1970	1975	1980	1983	1984	1985
4-Firm	18.1	20.8	23.9	26.3	26.0	25.3	25.0	26.1	26.20/o
8-Firm	30.3	33.5	38.5	41.7	41.2	40.8	38.4	44.5	43.6
15-Firm	41.0	44.2	50.3	56.9	57.0	56.1	53.5	56.4	53.2
20-Firm	46.3	49.1	55.0	61.1	61.2	60.6	57.6	59.4	55,8

Concentration ratio-U.S. liquids reserves					
	1975	1980	1983	1984	1985
4-Firm	36.3	31.1	29.0	29.6	29.10/o
8-Firm	55.6	46.3	43.2	48.6	41.7
15-Firm	70.4	59.5	56.1	59.1	47.3
20-Firm	74.5	62.7	59.4	61.2	58.9

SOURCE: Office of Technology Assessment from American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets 1950-84, Discussion Paper #O14R, Oct. 1985; 1985 Data from Oil and Gas Journal and Independent Petroleum Association of America, Petroleum Statistics 1985.

farmouts with independents and may even be willing to share some of the costs rather than merely contributing drilling rights.[41] Moreover, if the merged companies cut back their unproven property acquisitions and exploration efforts, independents may be more successful in obtaining some of the better prospects with reduced competition from the majors.

There has been concern expressed that the new combinations will diminish competition within the domestic industry. But, by several commonly used antitrust enforcement measures, the oil and gas industry remains competitive. Concentration levels in liquids production and

[41]Remarks of Ray Hunt, at SMU-ISM conference on Lower World 011 Prices in Dallas, September 1986.

reserves are still within historical levels (see table 39). The Federal Trade Commission has characterized the oil and gas production industry as "not highly concentrated."[42] Applying the current antitrust enforcement guidelines used by the Department of Justice and Federal Trade Commission to the market for crude oil, no merger between competing oil companies is likely to be challenged based on its effects in the overall crude market. In several large mergers, the Federal Government found significant downstream antitrust problems and ordered divestitures of certain downstream marketing and refining operations before approving the mergers.

In testimony before Congress, several witnesses questioned the adequacy of the standard measures for assessing mergers among large oil companies. Concentration ratios, HHI and other indices are primarily concerned with measuring the effects on market share of horizontal mergers (combinations between competing companies), and do not adequately reflect the true impacts on competition of mergers in the vertically integrated oil industry. For example, it was noted that the six largest oil companies could combine into a single giant company without exceeding the HHI indices triggering enforcement review.[43] Moreover, they noted, traditional antitrust and competition considerations were not the only areas of economic or social concern raised by the mergers.

[42] See testimony of Timothy J. Muris, Director, Bureau of Competition, Federal Trade Commission in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 71, citing a 1982 FTC study on concentration in the 011 industry. See also, American Petroleum Institute, *Market Shares and Individual Company Data for U.S. Energy Markets: 1950- 1984,* Discussion Paper, October 1985. Estimates of 4-firm and 8-firm concentration ratios in the oil industry have been fairly steady, varying only a few percentage points either way since 1970. The 1982 Department of justice Merger Guidelines use numerical standards to ascertain whether a proposed merger between competing companies may tend to affect competition adversely—the Herfindahl-Hirschman index or HH 1. The government is most likely to challenge a proposed merger if the post-merger H H I index is above 1,000 or if it increases the post-merger HHI is increased by more than 100 points to above the 1800 level. "The HHI measured in terms of U.S. production is only about 270 and in terms of U.S. crude oil reserves is approximately 329. All of these values are well below the 1,000 HHI level that normally triggers potential antitrust concern with a merger between competitors. " Testimony of Timothy J. Murris in *Oil Industry Mergers, supra* note 13 at 234-237.

[43] *Oil Industry Mergers, supra* note 13, at 204.

Increase in Long-Term Debt

The wave of acquisitions and anti-takeover defensive tactics added substantially higher **levels of debt** for the oil industry as a whole, as well as for individual companies. The Department of Energy found an increase in debt equity ratio among the Financial Reporting System (FRS) companies from 34.8 to 49.5 percent in 1984 alone, with much of this increase attributable to the effects of the Chevron-Gulf, Texaco-Getty, and Mobil-Superior takeovers.[44] OTA's review of a group of oil companies also shows higher debt levels for most merged companies (see table 37). Total long-term debt of the companies studied **more than doubled between 1983** and 1985. The largest increases were by firms involved in takeovers; their debt levels nearly tripled in 1983 to 1984 but repayments in 1985 lowered their overall long-term debt to 2½ times the 1983 levels. The heavier debt loads, at least in the short term, have been accompanied by lower total expenditures by the combined companies on exploration and capital investment in 1985 than in 1984. Among the companies not involved in takeovers, new long-term debt was used to retire prior debt at higher interest rates, to repurchase shares, to buy assets, and to provide additional capital for investment. The highest debt to debt plus equity ratios, a common measure of debt load or leverage, was shown by the two companies that successfully averted hostile takeover offers—increasing from 0.23: 1 in 1983 to 0.72:1 in 1985.

[44] U.S. Department of Energy, Energy Information Administration, *Performance Profiles of Major Energy Producers 1984, 20-21 (1986).* The FRS companies are a group of companies that are required to file detailed annual reports. The FRS companies were selected from the top 50 publicly owned domestic crude oil producers in 1976 who had at least 1 percent of either the production or reserves of oil, gas, coal or uranium, or 1 percent of refining capacity or or petroleum product sales. In 1984 the FRS group included: Amerada Hess Corp.; American Petrofina, Inc.; Ashland Oil, Inc.; Atlantic Richfield Co.; Burlington Northern, Inc; Chevron Corp.; Cities Service Oil Co.; Coastal Corp.; El. du Pent de Nemours & Co.; Exxon Corp.; Getty 011 Co.; Gulf Oil Corp.; Kerr-McGee Corp.; Mobil Oil Corp.; Occidental Petroleum Corp.; Phillips Petroleum Co.; Shell Oil Co.; Amoco Corp.; Standard Oil Co.; Sun Company, Inc.; Superior Oil Co.; Tenneco, Inc.; Texaco, Inc.; Unocal Corp.; Union Pacific Corp.; and United States Steel Corp. Four acquired companies, Cities Service, Gulf, Getty, and Superior, all filed separate FRS reports for 1984 because the mergers were not fully complete.

Many of the corporate acquisitions followed intense, and sometimes bitter, battles for corporate control. The impacts on corporate finances of defensive tactics adopted to fend off unwanted or "hostile" takeover offers raised concerns about the targets' future ability to fund exploration activities. In several successful takeover defenses, the target companies averted the takeover by buying the offerors' shares at a premium. In others, the target merged with a friendly "white knight", which often outbid the original offerors. The defending company was left with much higher debt. The unsuccessful offeror was left with a sizable gain on the stock transaction. Results such as this have led some raiders and other critics to contend that the target managements were motivated more by concern over protecting their own jobs than **in advancing the shareholders interests.**

An increase in long-term corporate debt is not by itself reflective of a weakened financial position. Debt and equity are the two principal means of raising capital for acquisitions and for capital spending. Increased debt has some risks, however. Debt brings with it a requirement to pay interest that, unlike dividends, generally cannot be deferred. High debt levels among oil companies raise two concerns: reduced flexibility in deciding how to spend its available cash flow; and reduced commitments to exploration and production as assets are sold and capital expenditures are cut to pay off debt.[45]

Effects on Exploration

The pattern of reduced exploration expenditures following recent mergers tends to contradict some of the earlier studies and examples cited in testimony in 1984 at the height of the mergers. Following the acquisitions of Marathon by U.S. Steel, Conoco by Du Pent, and Belridge by Shell, exploration expenditures were reported to have increased. But these results predated the more recent round of mergers and both the U.S. Steel and Du Pent acquisitions involved essentially new entrants into the oil business that operated their purchases as separate subsidiaries. More recent mergers have involved the disappearance by absorption of one energy company into another and the overall contraction of the combined entity, with lower production levels, reserves, and exploration expenditures.

During the debate over the effects of mergers and acquisitions in the oil industry, many of the representatives of acquiring companies, their investment bankers, and their defenders strongly denied that exploration efforts would be reduced.[46] Some company executives even suggested that exploration could be expanded because of efficiency gains and the stronger cash flows and asset bases of the merged companies. However, others inside and outside the industry argued as strongly that exploration would be cut because the newly purchased reserves reduced the incentive to look for more oil and repayment of the new long-term debt would **divert** cash flow that otherwise might be used for E&D.

The available evidence strongly suggests that the short-term results of the merger activity for the U.S. oil industry as a whole are reduced spending on exploration, fewer wells drilled, and less R&D than there was before the mergers and, arguably, than there might have been had these firms continued as separate entities. The amount of this change is not possible to quantify, but is probably much less than the losses attributable to the decline in prices. The merger-related expenditure declines are probably less than those caused by low prices because the 1986 spending cuts by all companies tended to be as large or larger than the 1985 cuts by merged companies. The fact that merged companies took cuts in E&P and capital expenditures in 1985, while others were still spending at previous levels or higher, suggests that the mergers have significantly decreased exploration expenditures below levels that might have been maintained by independent entities. If, for example, Gulf, Superior,

[45] Total long-term debt over 40 percent of a companies total capitalization (Total long-term debt, plus total equity) is considered high, but not unmanageable, however debt levels of 70 percent of capitalization or more are a matter for concern.

[46] For examples, see: Supplementary material submitted by Standard Oil Company of California in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 540; response of Chevron U.S.A. to Committee questions, *id.* at 539; statement of Morgan Stanley & Co., Inc., *id.* at 516; and material submitted by the Department of the Interior, *id.* at 529. See also, Testimony of Joseph J. Wright, Office of Management and Budget, in *Impact of Corporate Takeovers, supra* note 2, at 610-612; and testimony of Professor Edward J. Mitchell, Graduate School of Business, University of Michigan in *Oil Industry Mergers, supra* note 13, at 359-60.

Getty, and Cities Service had remained separate and continued their active exploration programs and if these programs were cut at the industry average, the separate exploration expenditures added to the baseline expenditures for Chevron, Mobil, Texaco, and Occidental, respectively, would likely exceed the totals for the merged entities.

The merged companies typically cut combined capital spending significantly in 1984 to 1985, while other large oil companies were maintaining or increasing their investments. This pattern is also seen in other surveys of U.S. exploration and development expenditures shown **in table 40** for 1983 to 1985. Table 41 shows a similar pattern in different, but comparable data on domestic exploration expenditures in 1986 to 1987. When oil prices fell in 1986, the merged companies reduced exploration budgets that were already constricted, and the share of their cash flow directed at debt reduction is undoubtedly much higher than was anticipated when the mergers occurred.

There are others who maintain that it is purely coincidental that exploration expenditures of some combined companies were cut substantially after the mergers. In their view the reasons for the cuts were related solely to the anticipated future oil prices and the quality of the available exploration prospects. There are of course other fac-

Table 40.—Capital and Exploration Expenditures for Selected Oil Companies 1983-1985 (thousands of dollars)

	1985 capital and exploration spending	Percent change 1984-85	1984 capital and exploration spending	Percent change 1983-84	1983 capital and exploration spending
Exxon Corp	10,339,000	6.0	**9,755,000**	8 4	**9,000,000**
Amoco Corp	5,306,000	14.6	**4,630,000**	13,2	**4,091,000**
Shell 011 Co	4,080,000	3.9	**3,927,000**	37,8	**2,850,000**
Mobil Corp	3,513,000	– 7,7	**3,806,000**	–12 4	**3,330,000**
Superior 011	—	—	—	—	1,016,855
Combined	3,513,000	–7 7	**3,806,000**	–12 4	4,346,855
Texaco, Inc	2,824,000	–24 6	**3,744,000**	–26 O	3.833,000
Getty 011	—	—	—	—	1,223,319
Combined	2,824,000	–24 6	**3,744,000**	– 26.0	5,056,319
Atlantic Richfield Co	3,595,000	10,4	**3,257,000**	–2.9	3,355,384
Chevron Corp	4.035,000	– 15.7	**4,786,000**	– 18.0	3,067,000
Gulf 011	—	.	—	—	2,770,000
Combined	4,035,000	– 15,7	**4,786,000**	– 18,0	5,837,000
Sun Co Inc.	1,748,000	–26,5	**2,377,000**	83.7	1,294,000
Standard 011 Co.	4,277,000	83.6	**2,329,000**	1.3	2,298,000
Unocal Corp .	1,847,400	–5.0	**1,944,800**	11.1	1,751,000
Tenneco, Inc	1,719,000	– 1,7	**1,748,000**	8.6	1,609,000
Conoco Corp.	1,402,000	1.1	**1,387,000**	–20.5	1,744,700
Phillips Petroleum .,	1,060,000	–23.6	**1,387,000**	21,6	1,141,000
Amerada Hess Corp. ...	929,000	– 16,5	**1,112,161**	53.1	726,365
Occidental Petroleum Corp. .,	1,151,700	5.5	**1,091,240**	14.7	951,019
MidCon Corp.	354,869	● 8.2	**327,951**	8.9	301,229
Combined[a]	—	.	—	—	
Marathon Oil Co. . .	1,165,000	60.2	**727,000**	–25.0	969,000
Texas Oil & Gas Corp. . . .	739,400	–3.8	**768,679**	16,1	662,332
Internorth, Inc.	591,200	–8.8	**648,548**	155,2	254,152
Houston Natural Gas Corp. .,	**–**	—	**413,652**	33.0	310,971
Combined	**591,200**	–44,3	**1,062,200**	88.0	565,123
Diamond Shamrock Corp	**679,900**	7,0	**635,500**	36.1	466,853
Pacific Lighting Corp. .,	**527,114**	–7, 1	**567,335**	– 10.8	636,013
Coastal Corp.	**341,300**	122	**153,542**	34.8	113,893
American Natural Resources	**—**	—	**404,600**	34.4	301,100
Combined .,	**341.300**	–38.9	**558,142**	34.5	414,993

[a]Merger completed m early 1986

SOURCE OTA from 011 & Gas Journal and company annual reports

Table 41.—Changes in Planned Expenditures on U.S. Exploration and Production

	Actual 1985	June '86 budget	Percent change 1985-86	Actual 1986 est.	Jan. '87 budget	Percent change 1986-87
***Major oil* companies:**						
Amerada Hess Corp.	310	120	–61	95	75	–21
Amoco Corp.	3,170	1,650	–48	1,300	1,300	0
Atlantic Richfield Co.	2,300	1,035	–55	1,000	750	–25
Chevron Corp.[a]	1,800	1,200	–33	1,050	975	–7
El. du Pent de Nemours[a]	700	420	–40	500	550	10
Exxon Corp.	4,700	3,050	–35	2,700	2,565	–5
Kerr-McGee	140	75	–46	75	70	–7
Mobil Corp.[a]	1,460	1,020	–30	1,020	1,020	0
Occidental Petroleum Corp.[a]	375	260	–31	260	235	–10
Pennzoil	270	175	–35	140	120	–14
Phillips Petroleum Co[a]	455	335	–26	200	240	20
Shell Oil Co.	1,800	1,350	–25	1,645	1,520	–8
Standard	1,700	1,000	–41	1,250	1,150	–8
Sun Co., Inc.	820	625	–24	430	430	0
Tenneco, Inc.	565	240	–58	310	235	–24
Texaco, Inc.[a]	1,670	1,100	–34	1,000	900	–10
Union Pacific	400	200	–50	195	185	–5
USX Corp.[a]	1,255	725	–42	560	480	–14
Unocal Corp.[a]	945	680	–28	600	640	7
Total majors	24,835	15,260	–39	14,330	13,440	–6
Selected independents:						
Apache.	120	80	–33	65	25	–62
Burlington Northern[a]	430	95	–78	100	100	0
Diamond Shamrock[a]	190	90	–53	105	130	24
Enron[a]	200	100	–50	100	91	–9
Enserch	250	140	–44	158	103	–35
Freeport-McMoRan[a]	122	55	–55	55	52	–5
Louisiana Land[a]	260	155	–40	155	147	–5
Mitchell Energy	130	89	–32	65	65	0
Murphy	113	60	–47	50	50	0
Pogo Producing	115	70	–39	65	40	–38
Santa Fe Southern[a]	195	145	–26	100	95	–5
Transco Exploration	280	125	–55	125	120	–4
Total independents.	2,405	1,204	**–50**	**1,143**	**1,018**	**–11**

[a]Companies involved in major takeovers 1982-86

SOURCES OTA from Oil & *Gas Journal* July 21, 1986, and Jan 19. 1987

tors that contributed to lower exploration expenditures in recent years, such as lower property acquisition costs because of reduced offerings of Federal offshore leases and lower bonuses, cost deflation in drilling and services, and deferrals of major projects because of price uncertainty. These factors affected both merged and non merged firms alike, however.

Oil production may actually increase if the purchaser can exploit the acquired reserves more efficiently. The classic example of this was Shell Oil Co.'s acquisition of Belridge Oil in 1979. Following the merger, Shell invested in enhanced recovery to expand heavy oil production from Belridge's California reserves. More recently, a good geographic "fit" of acquiring and acquired companies was cited as an advantage in the Phillips' takeovers of General American Oil and Aminoil, and in Louisiana Land & Exploration Co.'s purchase of Inexco Oil. These transactions involved complementary reserves holdings in areas where the purchasers were already active and allowed expansion into other areas where they were not represented.

Some major acquisitions may have been motivated primarily by reserves replacement, rather than as a means of corporate expansion. Several companies that bought other firms for their reserves had not been particularly successful in replacing their reserves through exploration.[47] This motivation is suggested by the shrinkage of the post-merger companies as many unwanted producing properties and operations are sold or abandoned. The acquiring company may be successful in maintaining its production level in the future out of its purchased reserves, but it may support a production level that is less than the combined companies before the acquisition. Cumulatively, overall domestic production could drop because of reduced total spending on exploration.

It has been argued that mergers need not result in reduced exploration and fewer reserves added. For example, a merger might create a new entity that is more efficient and successful at finding oil than its predecessors. Moreover, the combined firm would still face the need to replace the reserves lost through production (assuming it maintains the same production level after the merger) and would still be subject to requirements to drill many of its leases or lose them. The combination might lead to improved economies of scale by eliminating or reducing duplicative overhead and nondevelopment-related expenditures allowing more productive use of the combined financial resources and technical people.[48] The Department of the Interior has suggested that even if the merged company only conducted the same amount of exploration as before, it could combine information on geology, and geophysics of exploration prospects and select the best drilling sites from a larger menu and it might actually improve its exploration results with less overall spending on exploration and fewer holes drilled than might have been spent by the firms separately.[49] (This suggested result is questionable, however, since high grading would not necessarily increase the amount of reserves found, particularly if the acquired company was no more successful at finding oil than the acquiring company or if the exploration staff responsible for the reserves position of the acquired company is laid off or leaves.)

Others doubt that there are any added efficiencies in oil exploration to be gained through the mergers among large oil companies. Historically, the range of finding costs posted by both first and second tier major oil companies have been similar. The biggest companies did not necessarily have the lowest finding costs. Moreover, most of the anticipated savings would come from cutting staff, which may lead to long-term inefficiencies in exploration from the lack of experienced technical people.[50]

it is too soon to tell whether the mergers will mean a net increase or decrease in exploration and production in the long term. Several merged companies, e.g., Chevron and Mobil, have made substantial efforts to pay down debt even with lower oil prices. In a few years, they maybe ready to reallocate resources to exploration and research from a stronger financial and resource position.

In the longer term, even at lower oil prices, many of the larger merged companies will again have cash available that could be used for E&P after reducing their long-term debt. It will then become more apparent whether the added debt burden, asset sales, and restricted exploration activities assumed to undertake the merger will have produced a sounder, more efficient enterprise better suited to an era of uncertain oil prices. Table 41 shows preliminary 1987 exploration budgets for some firms, and it is notable that several of the merged firms are slightly increasing their exploration budgets.

Other Restructuring Activities

Oil companies have adopted a variety of restructuring strategies which they believe will help them to compete in the current era of volatile energy prices. Mergers and acquisitions have been perhaps the most public aspect of the restructuring, but they have been only part of a range of industry responses to changing conditions.

[47] See Donald F. Textor, Todd Bergman, and Cristina Tiscareno, "Finding Costs and Reserves Replacements Results 1979-1 985," Goldman Sachs Investment Research, Apr. 2, 1986.

[48] See, for example, response of Chevron U.S. A. to Committee questions in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 539.

[49] Additional material submitted by the Department Of the Interior, *Legislation Affecting Oil Merger Proposals, supra* note 1, at 529.

[50] See, for exam Pie, the testimony of Howard W. Pifer, III, Managing Director, Putnam, Hayes & Bartlett, Inc., in *Oil Industry Mergers, supra* note 13, at 211.

Segmentation and "Dis-integration"

Changes in the world oil industry following the OPEC price shocks of the 1970s have contributed to the modification of the traditional integrated structure of some major companies. Maintenance of a secure source of crude supply is no longer a priority for many integrated companies because of: 1) current world overcapacity in oil production; 2) a greater diversity of sources for crude oil with decreased reliance on mideast OPEC oil; and 3) the widely shared expectation that oil demand (and hence sales) will grow only modestly through the end of the century.

The process of buying and selling of crude oil has also changed. Oil prices now can fluctuate much more rapidly than before. The traditional long-term contracts for crude, which used to account for 90 percent of U.S. supplies, have largely been abandoned, and in 1986 up to ***90*** percent of supplies from outside the United States were obtained on the spot market or at spot-market-related prices. Netback arrangements with foreign producers are a part of this trend .51 Many companies have turned to options trading to moderate the risks of volatile oil prices.

Increasingly, segments of the oil industry are being separated vertically and operationally. Some integrated companies no longer depend on their own reserves to supply their refining and marketing operations.[52] Downstream operations are frequently seen as separate from upstream exploration and production activities. The downstream activities are now treated as independent and important profit centers rather than as an outlet for a company's crude. In the early 1980s, this shift led to the closing of many company-owned retail outlets and a net reduction in domestic refining capacity as refineries were upgraded and outmoded facilities were closed. Some companies have begun to redeploy their resources to their most profitable segments functionally and geographically instead of maintaining an integrated nationwide operation from exploration and production to shipping, refining, distributing, and marketing. For example, Ashland Oil sold many of its producing oil properties and relies more heavily on crude purchases to supply its refineries. Arco has pulled out of the retail oil market in the northeast. The cost-cutting and upgrading in refining operations as part of the early restructuring of downstream operations appear to have benefited some companies during the price plunge, with higher profit margins in refining helping to offset upstream losses.

According to some industry analysts, the growing segregation of upstream and downstream activities has contributed to a decline in the proportion of production revenues "plowed back" into acquiring and developing unproven properties. The 60 percent "plowback" in 1985 was the lowest in at least 5 years (see table 42). As noted earlier, a primary factor driving these changes has been the mediocre result of much of the E&D activity of the last 10 years reflected in the extremely high finding costs reported by much of the industry and the serious disappointments in exploration on the frontiers.

Cost-Cutting

Many restructuring programs were announced as efforts to cut costs and conserve capital and cash flow in anticipation of a prolonged period of low oil prices and sluggish demand. Although these changes were announced in early to mid-1985, most companies underestimated how sharply, and quickly, oil prices would actually fall in 1986 so that these programs were not fully in place to offset potential losses.

[51] Netback contracts are an arrangement between the seller of crude oil and the purchaser in which the ultimate price per barrel that the seller receives is tied to the sales price of refined products. This arrangement guarantees the refiner a minimum margin on product sales. Netback pricing was implemented by Saudi Arabia in late 1985 as part of its drive to regain market share. The terms of netback pricing arrangements are highly confidential, but by spring 1986 it was estimated that 3.5 to 4.5 million barrels of 011 per day were sold under these terms by the Saudis and others. Arthur Andersen & Co., *Oil and Gas Reserves Disclosures: 1981-1985 Survey of 375 Public Companies, 1986* at s-9. It should be noted that in early 1987, the Aramco Companies were reported to have signed a long-term fixed price agreement with the Saudis. Whether this marks a shift away from netback pricing is not yet known, since the terms of these agreements are confidential.

[52] " Crude oil production and crude oil refining and marketing are almost completely unrelated aspects of the petroleum business. Crude oil today is a fungible commodity in trade. Petroleum companies sell most of their crude to third parties and buy most of their crude for refining purposes from third parties. This is the very nature of the business. There is not a direct tie between the wellhead and the gasoline pump within a company. ' Statement submitted by Gulf Oil Corp. in response to Committee questions in *Oil Industry Mergers, supra* note 13, at 426.

Table 42.—Reinvestment in Oil and Gas Exploration and Production (375 publicly held oil & gas producers)

Plowback ratios	Us.					Foreign					Worldwide				
	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981	1985	1984	1983	1982	1981
Exporation and development[a]															
Majors	58%	64%	58%	68%	68%	32%	33%	37%	49%	47%	47%	52%	50%	62%	59%
Independents	57	56	62	105	134	75	59	52	93	99	62	58	60	104	133
Pipeline/utillty	74	78	83	107	106	51	63	81	90	94	68	75	79	104	103
Diversified	67	63	69	109	123	52	41	65	51	64	61	55	69	84	100
Weighted average	60%	64%	61%	77%	80%	37%	36%	42%	51%	52%	50%	53%	54%	69%	70%
All ***sources***[b]															
Majors	63%	111 %	62%	68%	68%	33%	57%	38%	49%	47%	500/0	89%	52%	62%	59%
Independents	93	93	92	131	145	75	65	63	122	104	91	89	87	130	144
Pipeline/utillty	113	90	107	108	106	74	63	162	92	94	107	84	111	105	104
Diversified	92	74	73	150	136	55	43	69	59	102	77	62	73	110	124
Weighted average	71%	103%	67%	85%	83%	38%	55%	45%	53%	59%	58%	85%	59%	74%	74%

[a]Excludes proved property acquisition costs
[b]Includes proved property acquisition costs

DEFINITIONS Plowback ratios are one measure of the level of a company's capital reinvestment m 011 and gas activities In this survey, plowback ratios are measured in lwo different ways
- E&D Plowback compares cash flows from net production revenues to the costs recurred to acquire unproved acreage and explore and develop new reserves
- All Sources Plowback compares cash flows from net production revenues to the costs recurred to purchase existing proved reserves and search for new reserves

These ratios are designed to measure the degree to which companies are using production cash flows and capital from other sources to replace reserves whether through exploration and development or by acquiring existing reserves

SOURCE Arthur Andersen & Co 011 & Gas Reserves Disclosures 1981-85 Survey of 375 Public Companies, ' 1986, s-40

Companies have reorganized divisions to eliminate duplicative functions and streamline activities. As part of accompanying changes in investment priorities and philosophies, many firms have made sharp reductions in exploration and development budgets. Within E&D programs, capital spending has been directed away from unproven property acquisition and frontier-wildcat drilling toward more development drilling and intensive development of existing fields. (These shifts are in addition to the increases in development spending that would normally follow the high levels of exploratory activity in the early 1980s.) Although more development drilling generally leads to more production, over the longer term, lower exploration expenditures eventually will lead to lower production unless reserves are replaced from other sources. A continuation of these trends implies less overall exploration and development expenditures, as well as less R&D spending in an industry with historically low R&D spending.

With less exploration activity, exploration and production staffs have been slashed. Corporation-wide personnel reductions have been achieved through early retirements, hiring freezes, layoffs, and voluntary and involuntary separations. Oil industry employment is down by about 25 percent from 1980 levels according to early 1986 estimates. personnel cuts have meant one-time charges against earnings for severance benefits at many companies, but may mean lower costs in the future. Of course, the risk inherent in the loss of so many experienced people is that they will not return to the industry if oil prices and exploration activity rebound.

Financial Strategies

Pressures from large investors and a general shift in corporate management philosophy have given greater emphasis to "enhancing shareholder values" in addition to the bottom line profit or loss **as** a measure of financial performance. Restructuring activities have included strategies to alter **a** corporation's capital structure and to improve key indicators of financial performance (e.g., earnings per share, assets per share, return on assets, return on equity). These strategies include buying-back shares, increasing or decreasing long-term debt, major asset sales, spinoffs, and writedowns. Companies have sometimes increased or maintained dividends to increase shareholder returns even when it was necessary to borrow money to do so.

Share Buybacks.–Some companies have elected to make strategic investments to reduce the number of their outstanding shares through share buyback programs to boost indicators such

as assets per share, cash flow per share, and earnings per share. Share buy backs are also seen as a means of increasing the return to shareholders, but the cash benefits only accrue to those disposing of their shares. Before the 1986 tax law changes, share repurchase programs were generally preferable for tax reasons to increasing dividends because of the capital gains treatment on any increase in share value. The 1986 tax law changes and sharply restricted cash flows probably have reduced or eliminated most current buyback programs, but should financial conditions improve, such programs will again compete with exploration as an alternative use of discretionary cash flow.

It has been widely thought that the announcement of a buyback program also benefits those who retain shares, because share prices generally go up following such an announcement. However, the long-term effect of this share price boost is less clear; there is no evidence showing that stocks of companies participating in buyback programs outperform industry averages.

Share repurchases by oil companies are part of a broader trend in the economy, the replacement of equity with debt. Total equity retirement from mergers, buy backs, and leveraged buyouts exceeded new equity offerings of nonfinancial corporations by almost $160 billion in 1984-85 and by $35 billion during the first half of 1986.[53]

Oil company buy backs have been financed out of internally generated funds, and in some instances through new long-term debt. Many of the buyback programs were directed at open market purchases, but some were undertaken to eliminate certain classes of preferred stock, or to acquire the shares held by hostile tender offerors. Phillips petroleum and Unocal went heavily into debt to buy back their own shares to thwart takeover bids.

As shown in table 43, share repurchases absorbed billions of dollars in oil company funds in recent years. To a certain extent, share buy-

[53]"Surging Business Debt May Not Be a Cause for Alarm, " *Business* Week, Nov. 10, 1986, p 28.

Table 43.—Share Repurchase Programs of Selected Oil Companies

Company	Year	Amount (millions)	Remarks
Phillips Petroleum Co.	1985	$4,972	Exchange offer of debt securities of $4.5 billion for 72.58 million shares of common stock in 1985
Texaco, Inc.	1984	$1,282	Purchase of common stock
	1983	74	
ARCO	1985	3,489	Bought back 28°/0 of outstanding common stock before suspending program in January 1986 because of lower oil prices
	1984	781	
Exxon, Corp.	1985	$2,687	54 million shares
	1984	2,631	164 million shares
	1983	762	21 million shares
Sun Co., Inc.	1985	221	Purchase of common stock for treasury
	1984	203	
	1983		
Standard Oil Co.	1986	$100	Authorized for share purchase
	1985	561	Includes $523 million for 11 million shares repurchased in Aug. 1984 tender offer
	1983-84	70	Open market purchase of 1.5 million shares.
Mobil Oil Corp.	1982-83	482	Repurchase of shares for treasury
Amoco Corp.	1985	806	Net increase in treasury shares
	1984	1,191	
Mitchell Energy & Dev., Inc.	1986	3.7	Purchase of 218,400 shares
Louisiana Land & Exploration Co.	1986	16.4	Repurchase of 604,700 shares before suspending authorized repurchase of 2 million shares in 1985-86
	1985	10.8	Purchase of 10.7 million shares 1983-85
	1984	11.6	
	1983	212.8	
Shell Oil Co.	1984	$5,900	Parent company Royal Dutch Shell purchased remaining 31 % of publicly held shares.

SOURCE: Office of Technology Assessment, based on company annual and quarterly reports 1984-87

backs raise the same concerns as mergers and acquisitions because substantial funds that could have been used for oil exploration were returned to shareholders. In the companies analyzed by OTA, share buy backs generally increased as a portion of discretionary cash expenditures relative to investment in E&P in recent years. In 1985, among large oil companies in the OTA group not involved in takeovers, share repurchase programs absorbed 23 percent of internal cash flow and domestic E&P spending 53 percent.

Changes **in Debt** Levels.–The oil industry had been historically cautious in using debt financing before the late 1970s, with the majors generally carrying lower debt loads than the independents. Many companies increased their debt levels in the early 1980s because debt financing was seen as more cost effective than equity financing to raise capital for expanded exploration activities. Also, interest payments, unlike dividends, are tax deductible, and an increase in debt, unlike an increase in shares, doesn't dilute shareholder values.

The oil industry has not been alone in increasing debt; all U.S. industries carried substantially higher long-term debt in 1986 than they did in 1980. *Business Week* estimates that the debt to equity ratio of the Nation's nonfinancial corporations soared from 35 percent in 1980 to an all time high of 47 percent in mid-1986.[54] Some Wall Street analysts view a rise in oil company debt and a corresponding decrease in equity as beneficial. They believe that U.S. oil companies are "overcapitalized" and thus, "too quick to make investments that might not have been very carefully worked out."[55] Greater reliance on external debt financing might, in their view, assure that exploration funds were invested in potentially more profitable areas and only after a rigorous review. Equity capital should not continue to be invested in oil and gas projects with below average returns, they reason, but rather should be returned to shareholders who might put it to more profitable use. Reducing equity capital is one reason for the trend in share repurchases discussed above.

Increased leverage has also been seen as a means to repel hostile takeovers. An SEC study of recent U.S. corporate takeovers found that companies that successfully fended off hostile takeovers tended to have higher debt loads than companies that were acquired.[56]

As noted previously, after initially increasing debt, many merged oil companies are now paying down or refinancing long-term debt to improve their leverage position. Chevron, Texaco, and Mobil have made significant progress in reducing the massive debt loads incurred in acquisitions of other companies, redirecting available cash flow to pay debt by slashing capital expenditures, cutting overhead, and selling assets.

Reducing the Asset Base.—Many companies have adopted strategies to downsize or reduce the asset base of the company, There are various sound business reasons for making a company smaller—to concentrate on core businesses, to remove subsidiaries that might create large losses in order to make the balance sheet stronger and to increase the percent return on assets. The asset shrinkage has been accomplished through a combination of spinoffs, sales, abandonments, and writedowns. Writedowns, reductions in the value of the assets carried on corporate books, were often taken to reflect price-related changes in the values of reserves and other assets, such as drilling rigs.[57] Asset sales bring cash directly to the company, while tax writeoffs yield some offsetting tax benefits.

In a move to improve other indicators of financial performance, some oil companies have resorted to spinoffs of unprofitable mining or drilling contractor subsidiaries to remove their im-

[54] Ibid

[55] See "Restructuring Shifts Focus of Oil Industry," *Oil and Gas Journal*, Nov. 18, 1985, pp. 87-92, citing Kurt Wulff of Donaldson, Luftkin, & Jenrette Securities Corp., p. 90.

[56] See John pound, Kenneth Lehn, and Gregg Jarrell, "Are Takeovers Hostile to Economic Performance?" *Regulation*, September/October 1986, pp. 25-30, 55-56.

[57] Some writedowns are largely voluntary decisions, but others are mandatory. SEC accounting rules for companies using the full cost accounting method, mostly Independent oil companies, require writedowns in the value of oil and gas reserves to reflect lower prices.

pacts on earnings. Other spinoffs involved the nonenergy businesses that oil companies bought during the 1970s diversification trend. When these subsidiaries are "spun off" or sold, the assets of the parent company are adjusted downward by an amount reflecting the value assigned to the newly separated entity. Interests in the newly independent entities are distributed to shareholders and then can be separately traded, creating additional opportunities to realize value on corporate assets. Examples of this trend include: Amoco's spinoff of Cyprus Mining; Arco's sale or liquidation of most nonenergy activities of its Anaconda Minerals subsidiary; and Noble Affiliates' spinoff of its drilling services subsidiary.

Oil and gas writedowns have generally been of very high cost reserves in remote frontier areas, e.g., Arco's writeoff of North Slope gas reserves. Other writedowns reflect discontinued operations or anticipated losses on asset divestitures, such as Mobil's writedowns in preparation for its planned divestiture of Montgomery Ward Department Stores.

Looking for New Internal Sources of Funds.– As companies look internally for new ways to generate cash flow, some have turned to employee pension funds as a potential source of funds. Exxon and Phillips have announced plans to tap overfunded employee pension plans by closing out the existing plans, purchasing annuities for participants and taking the excess funds, and starting a new employee pension plan. (The plans have "excess" funds over their anticipated liabilities because their investments have performed well.) Exxon anticipates that it will recapture about $1 billion from its employee pension fund, an amount equal to roughly one-third of its domestic E&P spending in 1986. This option may appear attractive to other large companies.

Creation of New Financial Instruments/Investment Arrangements.—The 1980s saw the creation and the expanded use of new financial instruments and investment vehicles, such as royalty trusts and master limited partnerships (MLPs), as ways to attract investment dollars and return value to shareholders. These arrangements offered several advantages over traditional stock ownership and previous investment devices. For example, MLPs pay no corporate income tax and thus pass through income to the partners or "unit holders" along with a share of partnership deductions that can be applied on the partners' personal income tax returns. (As discussed below, the 1986 tax law changes have limited some tax aspects of oil and gas MLPs.) The MLPs and royalty trust units also can be freely traded on stock exchanges and are thus more liquid than previous vehicles.

MLPs have also become an attractive mechanism for both small and large oil companies to return value to shareholders in response to pressures from aggressive investors or takeover threats. Some companies transferred many of their producing oil and gas properties to MLPs and royalty trusts and distributed interests to shareholders. The interests in the partnerships and trusts can be separately traded, perhaps resulting in a greater return to investors, while the parent company retains a managing interest and control over the properties. Some companies have also offered shares in the partnerships and royalty trusts to the public to raise exploration funds as an alternative to issuance of new common stock or long-term debt. (Some examples include Mesa Petroleum's Mesa Energy Partners, Sun Co. 's Sun Energy Partners, and Transco Energy's Transco Exploration Partners.)

Royalty trusts were a popular vehicle for independents to attract funds from outside investors for development drilling. But the creation of royalty trusts by converting existing corporate oil operations drew much criticism because they were seen essentially as a liquidation of a company's reserves position. Royalty trusts were said to reduce the availability of internally generated cash flow for exploration because income from the producing reserves in the trust and related corporate tax incentives were transferred to investors, who might not reinvest them in the oil industry.[58]

These vehicles drew billions to petroleum investments, but their future attractiveness is clouded by uncertainty over tax treatment of the

[58] See, for example, testimony of John H. Lichtblau, President, Petroleum Industry Research Foundation, Inc., in *Legislation Affecting Oil Merger Proposals, supra* note 1, at 374.

investment, the currently poor oil price outlook, and the prospect of lower overall tax rates. Although the tax bill maintained some of the tax advantages of oil and gas investments, there is concern that with lower tax rates, high-income investors will be less likely to invest in risky oil and gas ventures without a significant risk premium.

The 1986 tax law changes preserved many of the tax benefits for oil and gas exploration that can still be passed through to the unitholders. They did, however, limit the deductibility of "passive" losses from the partnerships, which could further diminish their attractiveness. Such passive losses can only be charged against similar passive income and cannot be used to shelter other income unless the partner shares in the risk of the venture at a level in excess of the investment. To continue the tax shelter aspect of oil and gas investments, investors must share liability exposure. Some industry tax experts have suggested that new investment packages will be created to overcome the passive loss restriction—perhaps a combination of a partnership interest and an insurance policy to cover losses in excess of the participation.

Effects of Restructuring

The long-term effectiveness of these restructuring efforts will not be known for several more years. Many cost-cutting moves will not provide immediate actual savings, and the sudden price drop and slide in revenues this year appears to have caught many companies by surprise. In addition, because major restructuring is unlikely to have been undertaken at random—each kind of restructuring was more likely to be undertaken by those companies most in need of the potential benefits it offered, or most vulnerable to it if the restructuring was imposed—the results of industrywide surveys of financial performance will be ambiguous about the "success" of restructuring. For example, many companies absorbed by hostile takeovers were vulnerable to such takeovers because of financial weakness; these companies may have been expected to undergo significant budget cutting with or without mergers, perhaps at levels greater than industry norms. Thus, post-merger statistics showing reduced investment levels beyond industry averages must be interpreted carefully to separate the effects of the takeover from other market effects.

Nevertheless, it is quite telling that extensive assurances about the positive effects of mergers were given to Congress in hearings held to explore the effects of the wave of mergers on the industry, and the more easily measured of these positive effects (increased E&D activity) have clearly not materialized. It seems clear that the **short-term** effects of mergers on E&D spending, and probably on R&D as well, have been negative. The short-term effects of mergers on less easily measured characteristics, such as the "efficiency" of E&D activity, and the effects of other restructuring activities have not been carefully measured.