CHANGING PRODUCTIVITY IN U.S. PETROLEUM EXPLORATION AND DEVELOPMENT

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Abstract

This study analyzes sources of productivity change in petroleum exploration and development in the United States over the last ten years. There have been several major developments in the industry over the last decade that have led to dramatic reductions in the cost of finding and developing oil and natural gas resources. While some of the cost savings are organizational and institutional in nature, the most important changes are in the application of new technologies used to find and produce oil and gas: 3D seismology, horizontal drilling, and deepwater drilling. Not all the innovation is endogenous to the industry; some rests on outside advances (such as advances in high-speed computing that enabled 3D seismology), as well as learning-by-doing. The increased productivity of mature petroleum provinces like the U.S. helps to maintain competition in the world oil market as well as enhance domestic industry returns.

Key Words: petroleum supply, technical change, world oil market

JEL Classification Nos.: Q31, O31

Acknowledgments

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A special debt of gratitude goes to Brian Kropp, who collected the data and literature used in this study, prepared the figures and calculations, proofread drafts, offered many suggestions for improvement, and reduced the number of mistakes in the manuscript. Of course, none of the above is responsible for the shortcomings that remain.

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Chapter 1

EXPLORATION AND DEVELOPMENT: LEVEL OF ACTIVITY AND INDUSTRY PERFORMANCE

The process of exploring for oil and natural gas has changed a great deal since the days when prospects were identified on the basis of surface oil seeps or topographical formations, and drilling was characterized by a group of roughnecks operating a rotary drilling rig and waiting for a gusher to erupt. Over the past two decades geologists and geophysicists have developed sophisticated seismic techniques to generate mountains of data that are fed into super computers via satellites and used to build complex three-dimensional structural and stratigraphic models of the earth. Similarly, drillers now use steerable downhole motors to create wellbores that bend and turn at all angles, use sensory systems next to the drill bit to determine its location and angle and the composition of the rock layers as they are encountered. And, where not long ago the search for hydrocarbons was restricted to land areas or shallow water, now the technology has been developed to explore in water too deep to use fixed leg platforms. In this environment remote drilling systems must be used, production platforms must float, and pressures and temperatures are such that oil and gas flowing through subsea pipelines can turn to paraffin and crystals.

Some of the changes in the technology of petroleum exploration and development rival in imagination and expense those involved in exploring outer space. They are a central part of a dramatic story of productivity change that has occurred in the industry in only ten years. This report will document the changes in technology, along with a number of organizational and institutional factors that are responsible for reducing costs and boosting productivity in the industry.

The motivation for many of the changes described here results from increasing pressure to reduce costs of production. The decline in the price of oil after 1981, including especially a fifty percent cut in the price early in 1986, and the prospect that the price would not rebound in the foreseeable future, meant that firms had to find new ways of doing business. Above all, they had to reduce costs in order to turn profit margins around. The story of productivity change in the industry is very much a story of how the industry responded to the pressure to reduce costs of production.

The requirement to reduce costs had to be achieved, moreover, in spite of the inexorable effect of depletion working in the opposite direction.[1] Depletion of the resource base raises costs of production. As reserves are found and extracted over time, it becomes more difficult and more expensive to replace those reserves. Firms will try to find and

[1] Added to the depletion effect is the rising cost of actions taken to safeguard the environment. Over the last twenty years firms have been required to meet increasingly stringent standards for controlling air and water pollution, and as a result have had to adopt more expensive practices for mitigating the effects of their activities on the environment. In effect, the costs of safeguarding the environment that were once ignored by firms have now been internalized into their profit statements.

produce the least costly and most profitable reserves first, and are likely to find the largest deposits first even by accident. Unless technology improves to make it easier to find and produce the next generation of resources, the average cost of production will inevitably rise over time. The pressure to lower costs makes the petroleum industry especially cognizant of the need to undertake research and development of new technologies.

It is of interest to note that the U.S. petroleum industry operates in an environment in which the price is determined in the international market largely as a result of the level of supply and demand that occurs in the rest of the world, while costs of production are determined by geologic conditions that are unique to the U.S. In order to compete in the international market, therefore, U.S. firms must be able to produce at unit costs that are lower than the world price. Indeed, in order to survive in the U.S. market without the benefit of import controls, U.S. producers must meet the same standard.

SCOPE OF THE REPORT

This is a report on the sources of productivity change in petroleum (that is, oil and natural gas) exploration and development in the United States over the last ten years. It is useful to clarify these terms from the beginning. Productivity refers to the amount of output that can be produce with a given amount of inputs. However, the measures of outputs and inputs can and will vary. For example, the measure of output may be the amount of oil and gas produced, or the level of success in finding new discoveries. Similarly, the measure of inputs may refer to labor hours or capital expenditure, or to the number of wells drilled or seismic crews at work. Whatever measures outputs and inputs are used, an improvement in productivity is analogous to a reduction in the average cost of the activity being measured, given that input prices remain unchanged.

The activities of concern here are oil and natural gas exploration and development. Exploration refers to the activities involved in the search for hydrocarbon deposits, including initial geological and geophysical information gathering (e.g., seismic surveying and reservoir modeling) and drilling to confirm the location of deposits (e.g., wildcat wells). Development refers to the activities involved in preparing a new reservoir for production, including drilling and completing wells that will be used to extract the deposit.

Our focus is on the primary factors responsible for changing productivity in the last ten years. There have been several major developments in the industry over the last decade that have led to dramatic reductions in the cost of finding and developing oil and natural gas resources. Some of the cost savings are organizational and institutional in nature, including a shift in the mix of independent and major firms, an increase in reliance on outsourcing for services, and the adoption of new management practices. Nevertheless, the most important changes are in the application of new technologies used to find and produce oil and gas. These include 3D seismology, horizontal drilling, and deepwater production systems. This report will describe these changes, how they came about, how they enhance productivity, and how they affect access to and use of the resource base.

The rest of this chapter describes the performance of the U. S. industry in recent years in terms of aggregate measures of outputs and inputs to give an overall perspective on the nature of the changes taking place. The following chapters attempt to explain these changes, not in some precise cost accounting sense, but more in terms of the qualitative contributions of different factors to productivity. Chapter 2 describes the organizational and institutional responses of the industry to the oil price collapse of 1986. These include, in addition to a massive reduction in employment, an increase in the importance of independent petroleum firms relative to the majors, the related buying and selling of assets, an increase in reliance on contract services, and the adoption of less hierarchical decision making.[2] Also included is a brief discussion of the increased costs of complying with environmental regulations. The next three chapters discuss the three most important technological innovations to come along in the last ten years, and perhaps since the beginning of petroleum exploration and development. Chapter 3 begins with the most important of the three, 3D seismology, including a description of the technology and how it is applied, and an analysis of the implications for productivity and resource development. Chapters 4 and 5 repeat the discussion for horizontal drilling and deepwater production systems. Where available, the analysis of these technologies draws on actual experience with their implications for production costs and productivity. Chapter 6 discusses the origins of these technologies and some implications that follow from their contributions to productivity. The discussion of origins focuses on the technological breakthroughs that were required for commercial success. Among the implications considered are the role they will play in the continuing vitality of the petroleum industry in the U.S., the performance and behavior of the international petroleum market, and the behavior of the world price of oil.

Before moving on to the details, however, it is useful to get a general view of the level of exploration and development activity in the U.S. and the various activities conducted at this stage of production. In addition, we present several industry-wide measures of productivity performance that the factors examined in subsequent chapters contribute to.

EXPLORATION AND DEVELOPMENT ACTIVITY IN THE U.S.

Exploration and development refers to all of the upstream activities that are required to find new oil and natural gas reserves and develop them to the point where they are ready to be produced. The major categories of expenses include geological and geophysical information gathering (such as seismic surveying and reservoir modeling), drilling exploratory wells for the purpose of locating and assessing the value of new reservoirs, and drilling development wells that will support a production plan over time. These upstream activities are undertaken to replace existing reserves that are depleted as they are produced over time. An inventory of prospects is necessary to support an exploratory program, and an inventory of explored prospects is necessary to support a development program.

Expenditures on exploration and development in recent years have been running at less than a third of what they were in the early 1980s. The explanation is simple. The incentive to invest in exploration and development is directly determined by expected earnings, which is determined in turn by the market price of oil (see Figure 1-1, end of this chapter). The industry is not neglecting investment in upstream activities, however, nor is the industry as a whole shifting new investment away from the U.S. and toward the rest of the

[2] A major firm is one that operates in all stages of production, from exploration and production to refining and marketing, while an independent firm is one that specializes in exploration and production.

world.[3] The ratio of exploration and development expenditures to net oil and natural gas revenues (see Figure 1-2, end of this chapter) has been increasing since 1987, and the pattern is the same for investment in the U.S. and in the rest of the world. This ratio, sometimes called the "plowback ratio," indicates that the industry increasingly has been willing to commit its financial resources to expansion of its reserves inventory, even while the price of oil and natural gas has been falling.

Equally interesting, what the industry has been buying for its exploration and development dollars has been changing in recent years. Comparing Figures 1-3 and 1-4 (end of this chapter), it may be observed that, while both the number of exploratory wells drilled and the level of upstream employment have declined in recent years along with the price of oil, the number of wells drilled has declined significantly more than the level of employment. For example, the level of drilling in the 1990s is less than half that in the years prior to 1973, while the level of employment in recent years remains above that prior to 1973. The latter observation may be of little comfort to the half million persons who have lost their jobs in the petroleum industry in recent years, but it does indicate that the industry has not been downsizing simply to prop up profits.

While the number of exploratory wells drilled annually since 1986 is comparatively low, the industry is becoming more selective in its choice of which exploratory wells to drill. In general, the preference is toward more expensive wells and toward prospects that have a greater probability of a payoff. The trend toward more expensive exploratory wells is most evident in the shift from onshore to offshore activity (see Figures 1-5 through 1-7, end of this chapter). In 1989, exploration expenditures in offshore areas exceeded that for onshore areas for the first time in history, and the gap promises to widen in the foreseeable future. The harbinger of future trends is given by the amount of investment in geological and geophysical information gathering illustrated in Figure 1-6. Expenditures for offshore information gathering have been fairly steady since the mid 1980s, while the same expenditures for onshore information (as well as for exploration in total) have fallen sharply. And, for the first time in history, beginning in 1994 expenditures for offshore activity exceed that for onshore. Offshore, and particularly the Gulf of Mexico, is clearly becoming the frontier area for petroleum exploration and development investment in the U.S. As we will see more clearly in Chapter 5, the payoffs warrant the focus of this investment.

The shift in focus to offshore targets also shows up in the amount of expenditures for development drilling (Figure 1-7). Clearly, the frontier for petroleum activity in the U.S. is offshore, and primarily in the Gulf of Mexico. This observation will be confirmed later on when we discuss deepwater production technologies and the future vitality of the industry.

On average, offshore exploratory wells are five to six times more expensive to drill than onshore exploratory wells (see Figure 1-8, end of this chapter). A similar cost differential occurs for development wells (see Figure 1-9, end of this chapter). As discussed in Chapter 5, drilling costs increase with water depth, and are especially expensive in deep water (i.e., a water depth greater than 1000 feet). As financial risks rise with drilling costs,

[3] An exception, as we will see in Chapter 2, is investments by major firms, who in contrast to independent firms are shifting to targets located outside the U.S.

the industry requires better geological and geophysical information to raise the probability of finding a commercial prospect (i.e., avoid "dry holes") when a well is drilled.

The total number of commercially successful oil and gas wells drilled is shown in Figure 1-10, along with the total number of dry wells drilled. It is clear that, since 1986, the industry has drilled fewer dry holes relative to successful ones, especially compared to the halcyon days between 1974 and 1985 when oil prices were exceptionally high. Part of the improvement in success rates may be attributed to an increase in the proportion of development wells relative to exploratory wells, including an increase in infill drilling (which involves drilling more wells into known reservoirs to increase the rate of production). Infill drilling is another way of raising current earnings in a period of depressed prices, although this type of activity does not contribute much to the capability of the industry to sustain production over time.

Another change in the apparent target of drilling efforts may be noted from Figure 1-10 (end of this chapter). By 1993, the number of number of successful gas wells drilled exceeded that of oil wells for the first time in U.S. history. The consequence of this shift in drilling targeted toward gas, combined with the fact that gas wells take longer to deplete on average than oil wells, was the rapid expansion in the number of producing gas wells over the last thirty years (see Figure 1-11, end of this chapter). In contrast, the number of producing oil wells has remained fairly stable.

To compare the amounts of oil and gas produced in the U.S., barrels of oil and cubic feet of gas must be converted to a common unit of measurement. Figure 1-12 (end of this chapter) makes the comparison using two separate units of measurement: heat content and market price. Using heat content, the volume of gas has exceeded the volume of domestic oil production since 1963 and the gap has widened after 1987. Using wellhead prices, the value of oil exceeded the value of gas until 1993. Since that date natural gas has been bigger business to the upstream segments of the domestic petroleum industry than oil.

MEASURES OF PERFORMANCE OF THE INDUSTRY

Labor productivity, as measured by the amount of oil and gas produced at the wellhead (in Btu's) per worker employed in exploration and development, has increased dramatically since 1986 (see Figure 1-13, end of this chapter), although is has not returned to the levels achieved in the early 1970s.[4] The same picture emerges when labor is augmented by other inputs to production, such as capital and materials, to obtain a measure of total factor productivity. However, such measures are not particularly meaningful indicators of productivity in exploration and development. The reason is that the volume of production varies for reasons other than the results of activities in exploration and production. Firms may increase or decrease the rate of production from available reserves in response to, say, a change in the price, rather than as a result of an increase or decrease in the inventory of reserves available for production. In periods when the rate of production exceeds additions to reserves, an output measure of productivity may overstate upstream productivity; conversely, when the

[4] The dramatic increase is due to the fact that employment dropped considerably faster than output of oil and natural gas.

rate of output is less than additions to reserves, an output measure will understate upstream productivity. While the rate of output must eventually come into line with the rate of reserve additions, a discrepancy can persist for an extended period of time. This issue is important to the present study because the focus on productivity change is limited to the last ten years.

A related consideration that limits the meaningfulness of output measures of productivity applied to exploration and development activities is that it may take some time before a change in upstream productivity results in a change in output. The new technologies under consideration here may lead, for example, to an immediate improvement in drilling success rates at the margin, but will have a delayed effect on the average success rate, and an even longer delayed effect on the level of output. Thus, factors that influence upstream productivity may not be fully evident in their effect on output for some time.

Notwithstanding the essential link between reserve additions and production rates, it is surprising how long a discrepancy between the two can persist. Annual additions to oil reserves have been consistently less than annual production for more than twenty years, and the reserve replacement ratio dipped below 50 percent after 1990 (Figure 1-14, end of this chapter). The reserve replacement ratio for natural gas was below that for oil between 1978 and 1990, but began to increase afterward and, for 1994 and 1995, was above unity. These two years represent the first annual back-to-back increases in gas reserves in twenty-eight years. Thus, except for the experience with gas in the last two years, rates of output were maintained with less inputs into exploration and development.

A better picture of productivity change in exploration and development is obtained by looking at the more direct and immediate results of upstream activities. In place of measures that use of the volume of oil and gas production, better measures of output are drilling success rates, discovery rates, discovery sizes, and finding costs.[5] Even at this finer level of distinction ambiguities can occur among the different measures of performance. For example, success rates in drilling may improve, yet total discoveries or average discovery size may fall, either because the inventory of large prospects declines (i.e., the natural depletion effect) or because new technology makes it easier to find smaller prospects. For this reason it is useful to compare a variety of measures of performance. While no one measure captures all aspects of upstream performance, together they can provide a good picture of how productivity has changed. As we shall see below, virtually all of them indicate that there has been a significant improvement in productivity in recent years.

We begin by examining productivity measures that use the number of wells drilled as the measure of input, with distinctions as to the type of well drilled. Figure 1-15 (end of this chapter) gives the overall success rates for exploratory and development wells, including both oil and gas wells. A success rate in this context is the percentage of exploration and development wells drilled that hit a commercial deposit of oil or natural gas, regardless of the size of the deposit or the potential extraction rate. Since development wells are drilled into known reservoirs, while exploratory wells are intended to find new deposits, the average success rate of development wells is understandably much higher than that for exploratory wells. The fact that the success rate for development wells is not at or near 100 percent

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[5] Such measures, it is noted, are also not particularly meaningful on a per-unit of labor and capital basis.

reflects the uncertainty involved in probing even known deposits.[6] Figure 1-15 shows that success rates for exploratory and development drilling have increased over time, and that exploratory drilling has experienced a dramatic improvement since 1990.

The same dramatic increase shows up in the rate of new field discoveries per new field wildcat well drilled (see Figure 1-16, end of this chapter). This definition of a success rate corresponds to the search for new resources in virgin territory, in contrast to exploratory drilling in general, which covers drilling in established as well as new areas.[7] As expected, the success rate is somewhat lower for wildcat drilling than for exploratory drilling, but they both show the same sharp improvement after 1990. While the improvements in success rates are no doubt related to the application of 3D seismic technology, it would be a mistake to attribute all of the gains to 3D. Some improvement in success rates may be expected simply because the industry is drilling fewer wells than before, and are therefore drawing on higher quality prospects than before.

The average amount of oil and natural gas that is found by each exploratory well, sometimes called oil and gas "finding rates," is another indicator of productivity because it measures reserve additions per unit of (drilling) effort. Both oil and natural gas finding rates have been increasing since 1986 after several years of continuous decline (see Figure 1-17, end of this chapter). This pattern reflects the cost-consciousness that has been imposed on the industry by the decline in oil and gas prices after 1981, and particularly after the sharp drop in 1986. As noted above, the industry has been more selective about the prospects it has been drilling in recent years. In addition, as we shall discuss below, after 1986 the industry developed and implemented improved 3D seismic technology that raised the probability of success.

The average amount of oil and natural gas contained in each new discovery is shown in Figure 1-18 (end of this chapter). Average discovery size for both oil and natural gas was trending downward until 1986, but has become remarkably flat since then and even shows signs of increasing in the most recent years. The relative turn-around in average discovery size in recent years is especially surprising for two reasons. First, discovery size is continuously updated over time, as continued development of the reservoirs leads to extensions and revisions of the amount of resources in-place that are credited back to the original discovery. Thus, more recent figures on average size will be biased downward relative to older figures simply because there has been less opportunity for revision. Second, discovery size should fall over time as the resource base becomes more depleted and the largest fields are discovered first. A reasonable hypothesis is that the new technologies described further below have been effective in finding and exploiting larger deposits.

For comparison with the above measures of performance, "yield per unit of effort" measures the volume of additions to oil and gas reserves per dollar spent on exploration and development activities. Exploration and development expenditures are commonly divided into two separate measures of the "level of effort" to reflect the distinct activities involved. Exploration expenditures are aimed at finding new discoveries, but this measure is ambiguous

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[6] I have been told that "lack of success" does not always mean a "dry hole." Sometimes drilling will be unsuccessful because of equipment failure or stuck pipe, in which case the well must be abandoned and redrilled. It is unknown how many such failures occur and whether they seriously distort the meaning of a success rate.

[7] A "rank wildcat" is a well drilled at least two miles away from any known production.

because the amount that is discovered in one year changes over time as revisions and extensions occur. Until a reservoir is fully developed, the magnitude of the initial discovery and the yield per unit of effort are unknown. Development expenditures, in contrast, are intended to delineate the extent of the discovery and to prepare the reservoir for production. The outputs of these activities are revisions and extensions, which are known for each year in which development drilling takes place.[8] Consequently, yield per unit of effort in this case is unambiguous. Note, however, that the yield curves for petroleum drilling (Figure 1-19, end of this chapter) have been increasing steadily since the early1980s, whether measured on the basis of exploration or development activity. Note, also, that the yield curves for oil and gas have increased noticeably since 1990. The similarity in the behavior of the yield curves for discoveries and for revisions and extensions is significant because trends in development costs are thought to be a good proxy for trends finding costs.[9] The reasoning is that if new discoveries are more costly to find because they are smaller or located in a harsher environment, their development costs will be more expensive too.

The inverse of “yield per unit of effort” is the “average finding cost” of new reserves; that is, expenditures on exploration and development divided by additions to reserves. As shown in Figure 1-20 (end of this chapter), the average finding cost for oil and natural gas have both declined by about 50 percent since 1982. Exploration and development activities are combined in this figure because of the similarities in trends in the two activities. It is emphasized that the level of average finding cost is less important than the trend over time. This result summarizes the dramatic improvement in productivity in petroleum exploration and development in the U.S.

CONCLUDING REMARK

The petroleum industry has experienced a dramatic improvement in productivity in the last ten years. The task the rest of this report is to examine the factors responsible for this improvement and to determine whether the reasons have implications for future resource development in the U.S. The factors that are most important in explaining recent productivity improvements are technological and will occupy most of our attention. However, we begin in the next chapter with an overview of the institutional factors affecting productivity.

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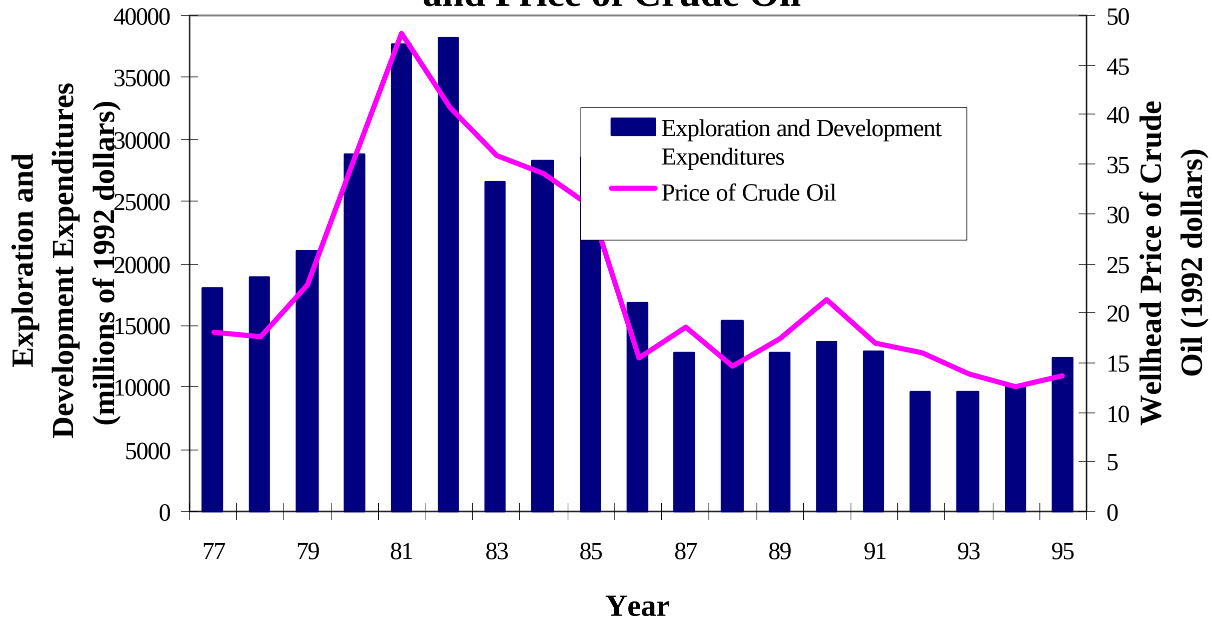
[8] Actually this is not strictly true. Revisions may come from exploratory (delineation) wells, and revisions can result from factors unrelated to drilling (e.g., a price increase).

[9] M.A. Adelman, “What Do Recent N. Sea Unit Cost Changes Mean?” *Oil and Gas Journal,* (Feb. 3, 1997) pp. 45-46.

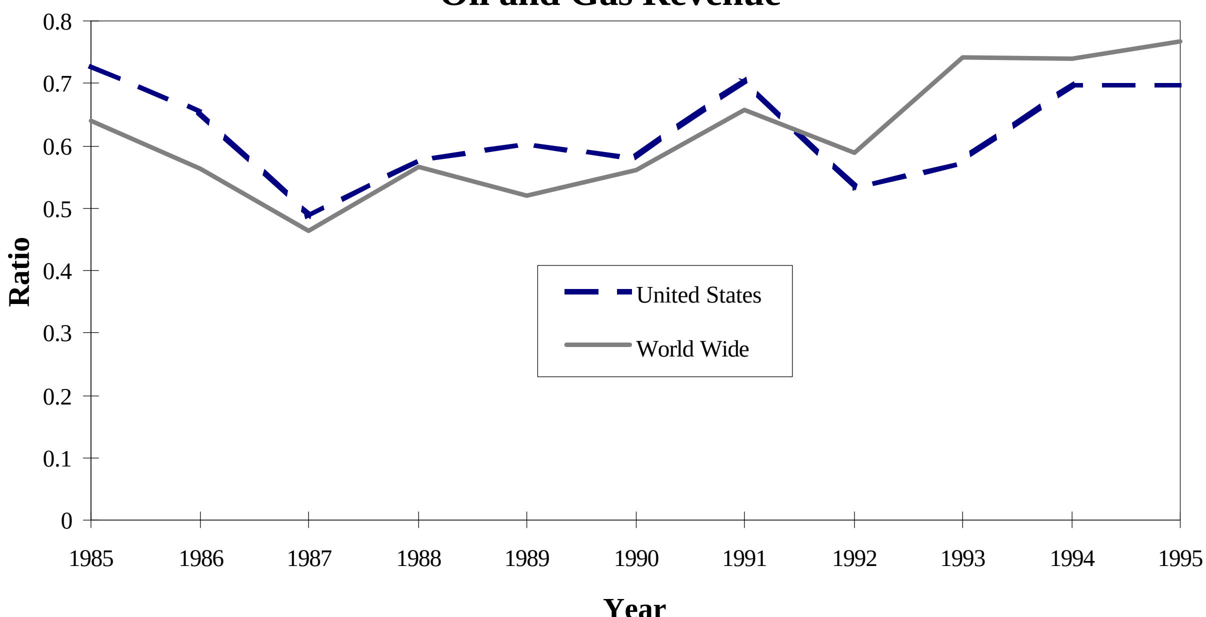
Figure 1-1
Exploration and Development Expenditures in the U.S. and Price of Crude Oil



Note: Exploration and Development Expenditure data are from 36 major oil companies.

Source: Energy Information Adminstration, *Annual Energy Review 1995*, July 1996; Energy Information Administration, Financial Reporting System, 1997.

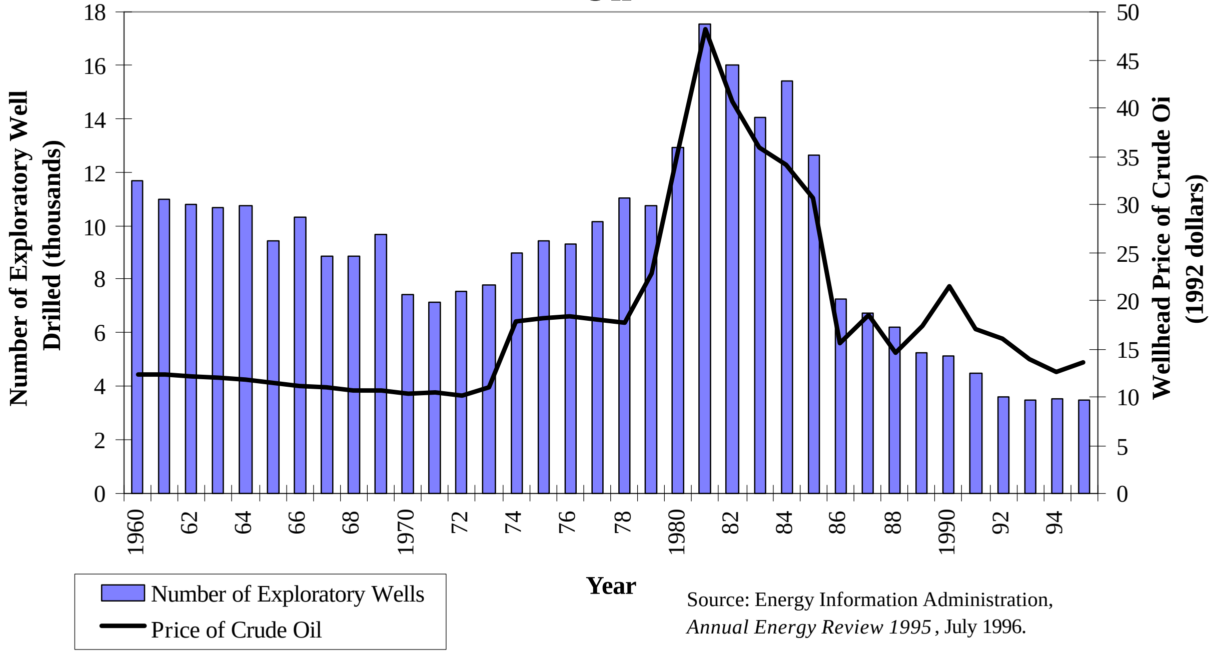
Figure 1-2
Exploration and Development Expenditures Divided by Net Oil and Gas Revenue



Note: Calculated from the expenditures and revenues of 92 firms operating in the U.S. and worldwide.

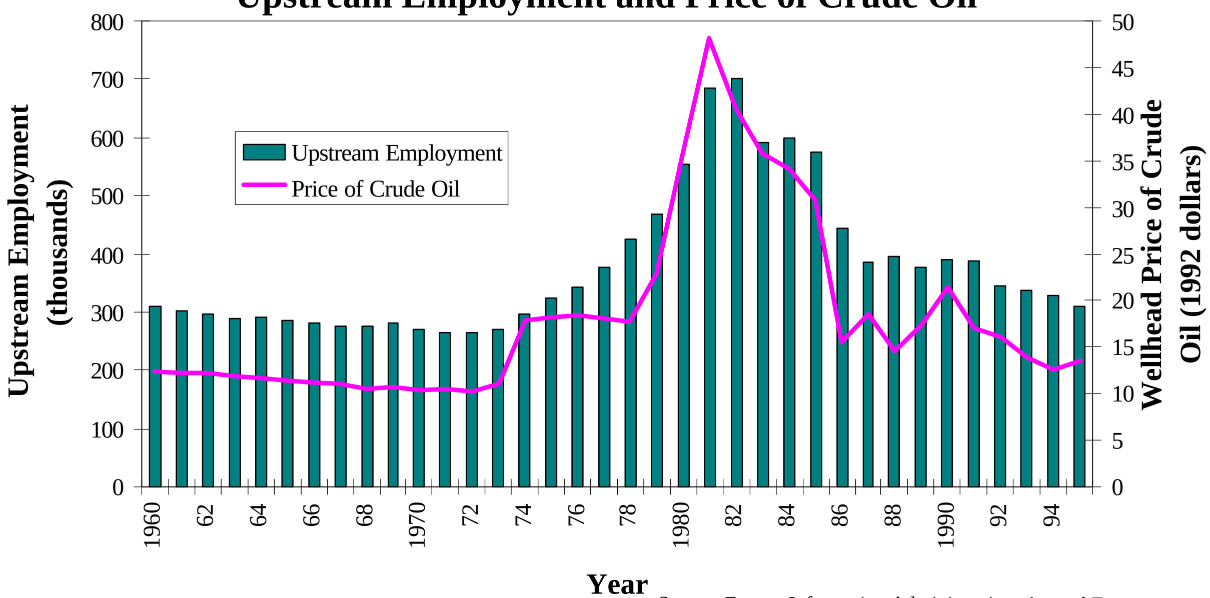
Source: Penwell Energy, *Company Performance Statistics Sourcebook*, 1997.

Figure 1-3
Number of Exploratory Wells Drilled and Price of Crude Oil



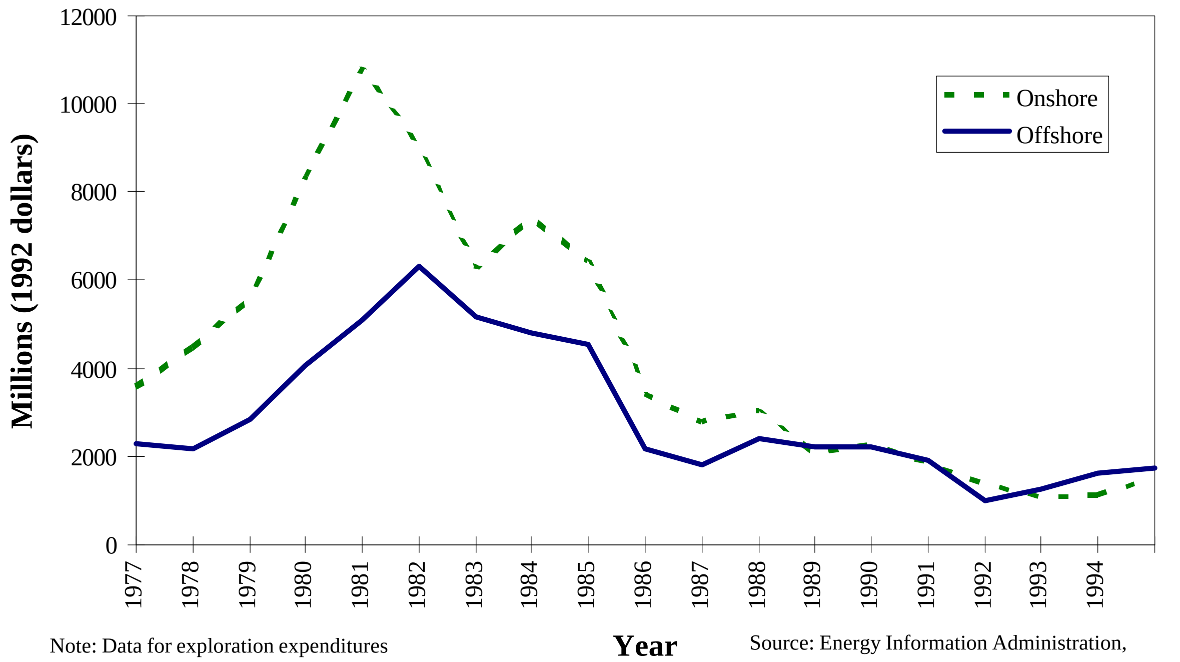
Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996.

Figure 1-4
Upstream Employment and Price of Crude Oil



Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996; Bureau of Labor Statistics, *Employment and Earnings* Various Years.

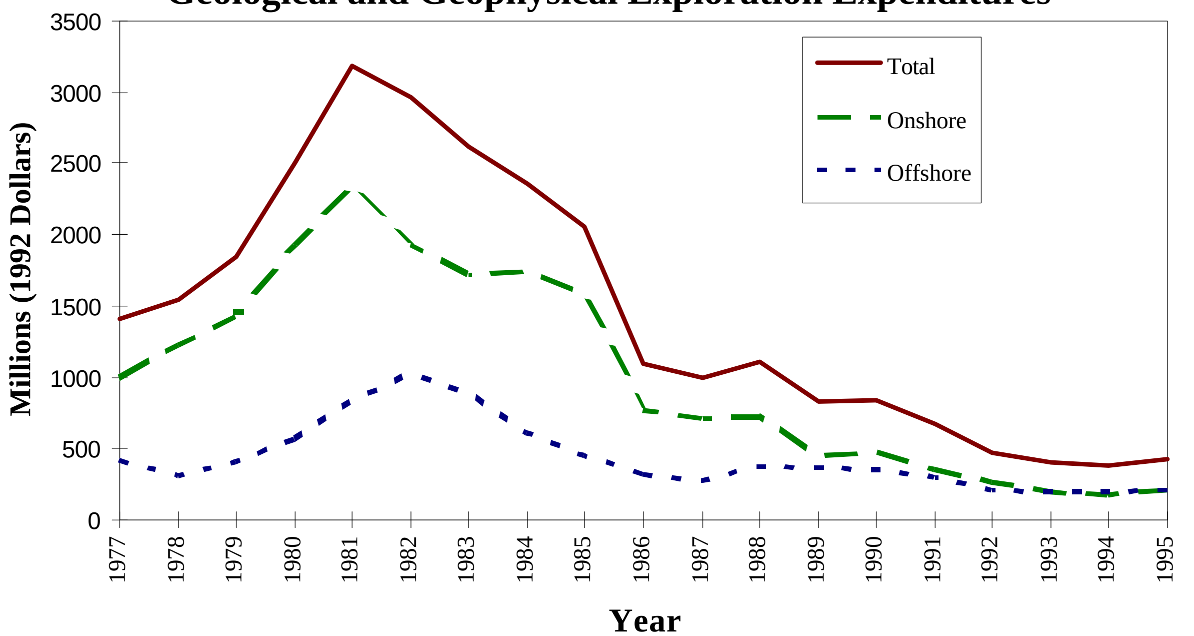
Figure 1-5
Exploration Expenditures, Onshore and Offshore



Note: Data for exploration expenditures are from 36 major U.S. oil companies.

Source: Energy Information Administration, *Financial Reporting System* ,1997 [electronic file].

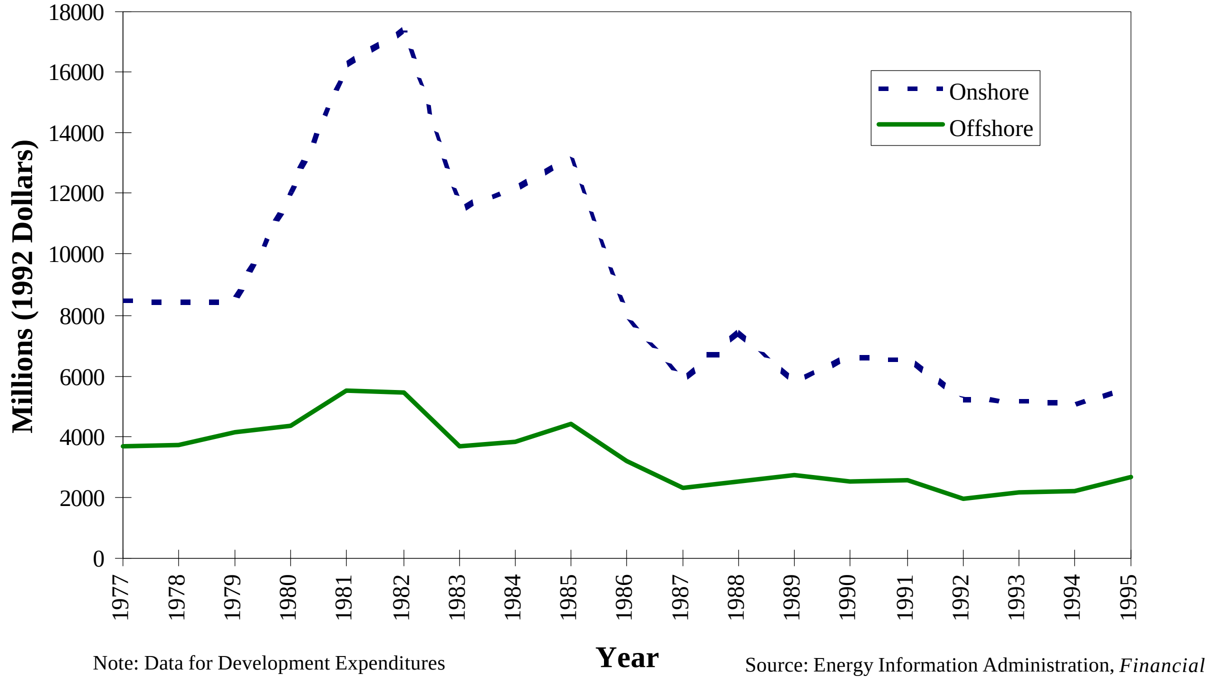
Figure 1-6
Geological and Geophysical Exploration Expenditures



Note: Exploration Expenditure data are from 36 major oil companies.

Source: Energy Information Administration, *Financial Reporting System* , 1997 [electronic file].

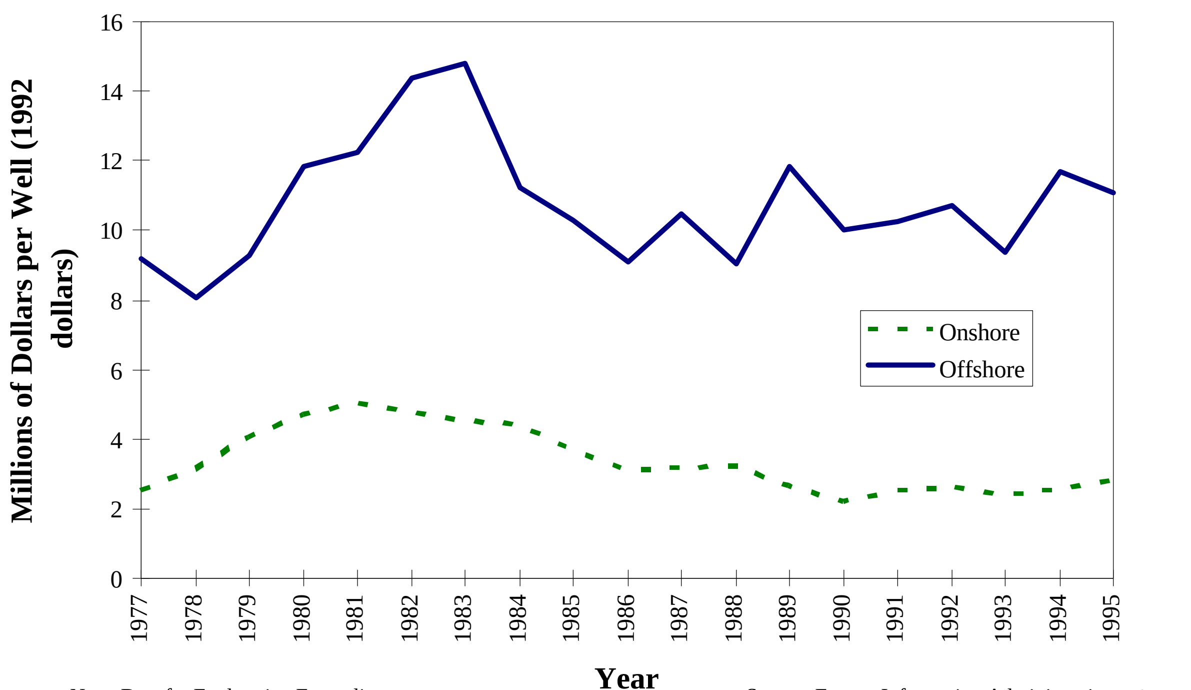
Figure 1-7
Development Expenditures, Onshore and Offshore



Note: Data for Development Expenditures are from 36 major oil companies in the U.S.

Source: Energy Information Administration, *Financial Reporting System*, 1997 [electronic file].

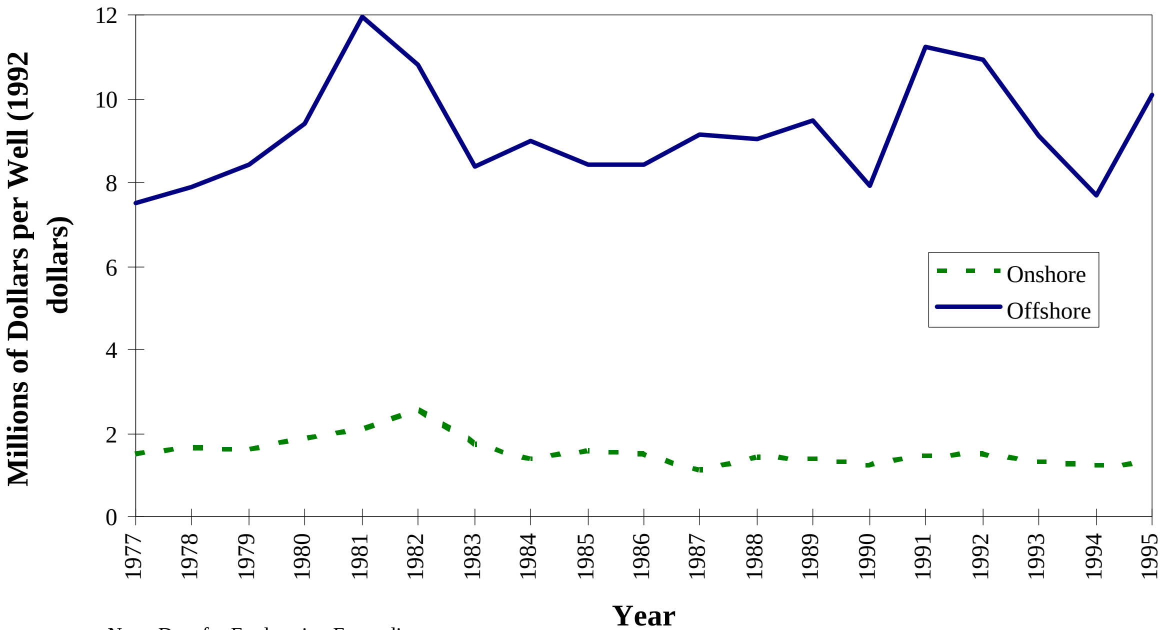
Figure 1-8
Average Cost of Onshore and Offshore Exploratory Wells



Note: Data for Exploration Expenditures are from 36 major oil companies in the U.S.

Source: Energy Information Administration, *Financial Reporting System*, 1997 [electronic file].

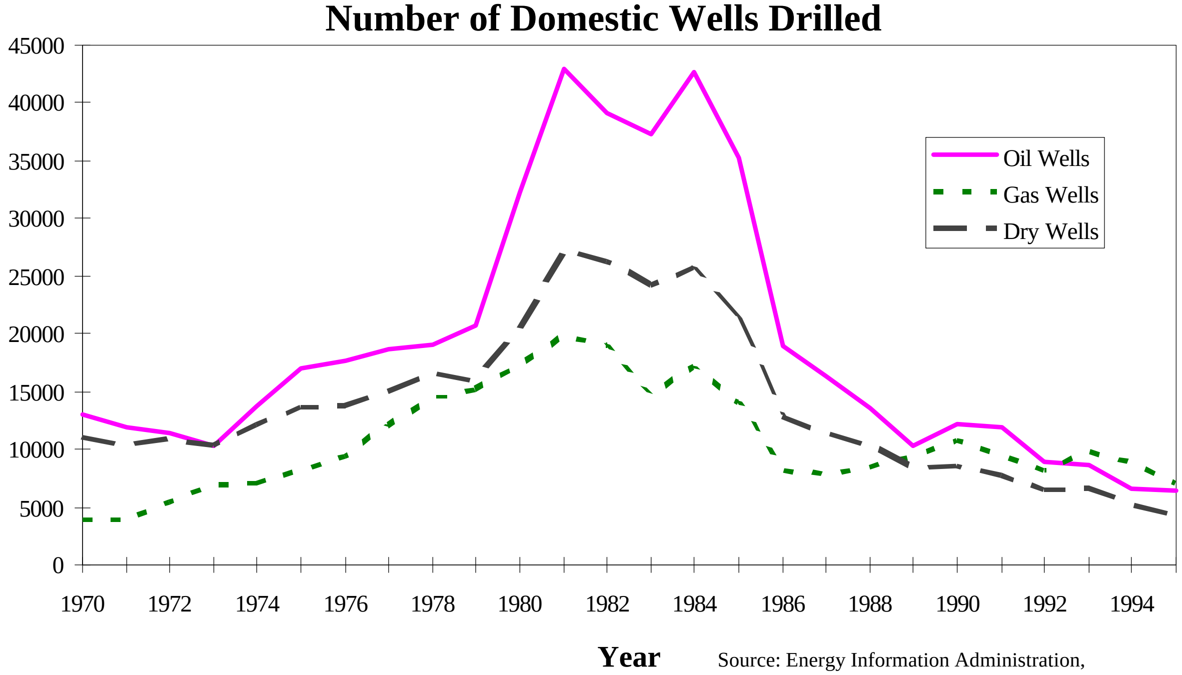
Figure 1-9
Average Cost of Onshore and Offshore Development Wells



Note: Data for Exploration Expenditures are from 36 major oil companies in the U.S.

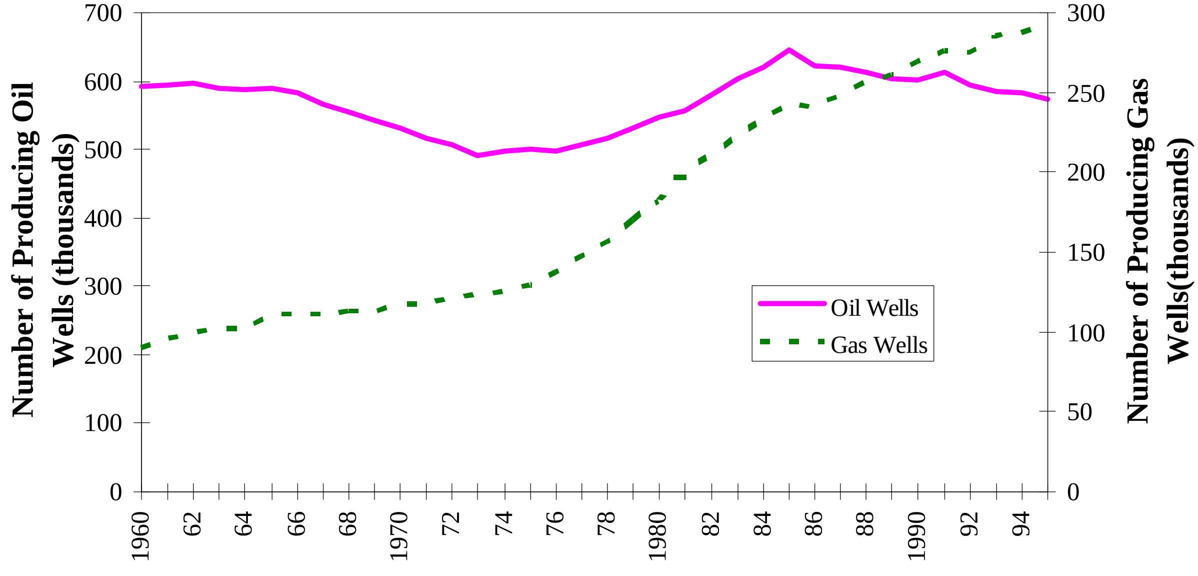
Source: Energy Information Administration, *Financial Reporting System*, 1997 [electronic file].

Figure 1-10
Number of Domestic Wells Drilled



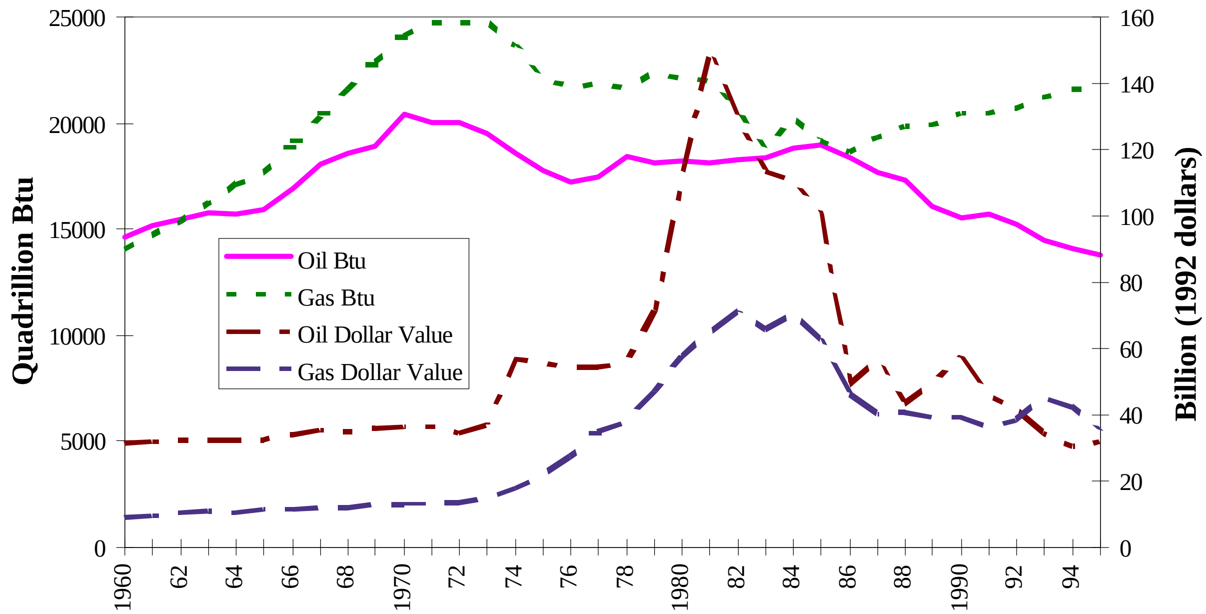
Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996.

Figure 1-11
Number of Producing Oil and Natural Gas Wells



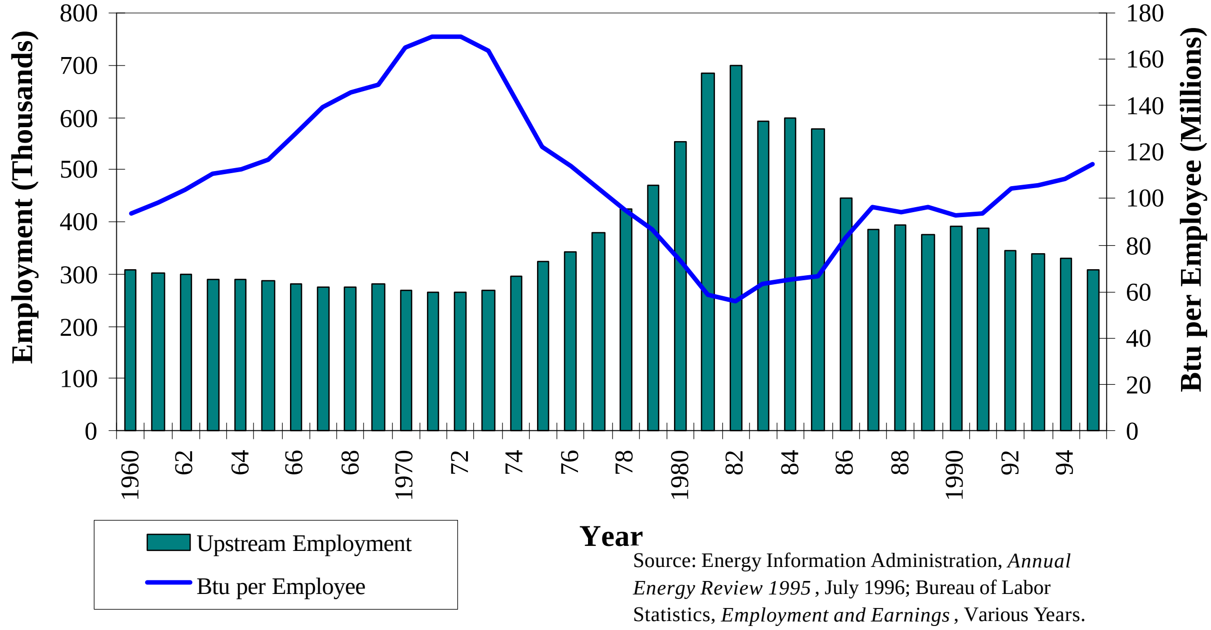
Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996.

Figure 1-12
Production of Oil and Natural Gas, Btu and Dollar Value



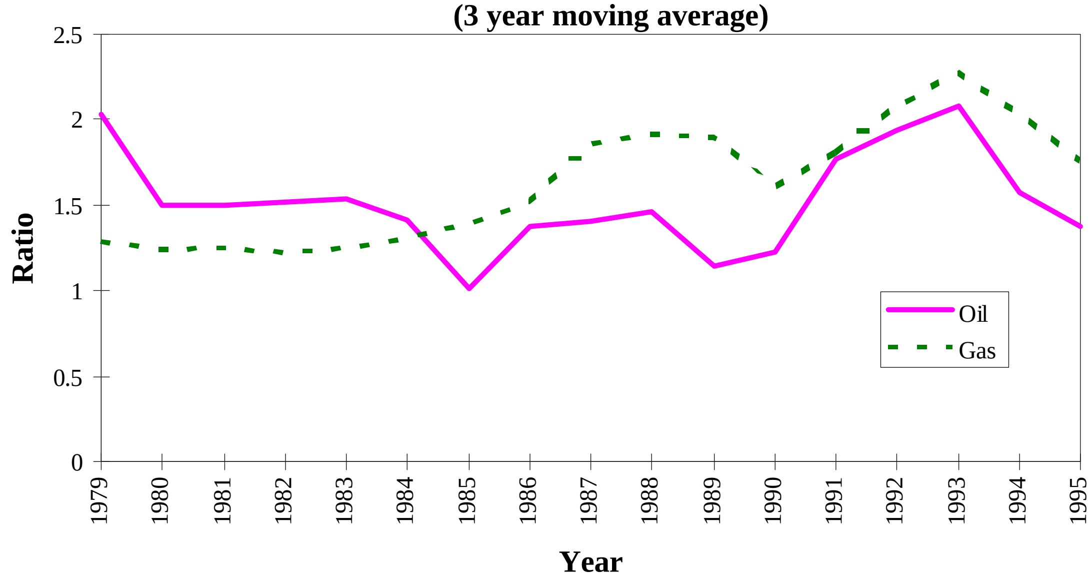
Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996.

Figure 1-13
Upstream Employment and Labor Productivity



Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996; Bureau of Labor Statistics, *Employment and Earnings*, Various Years.

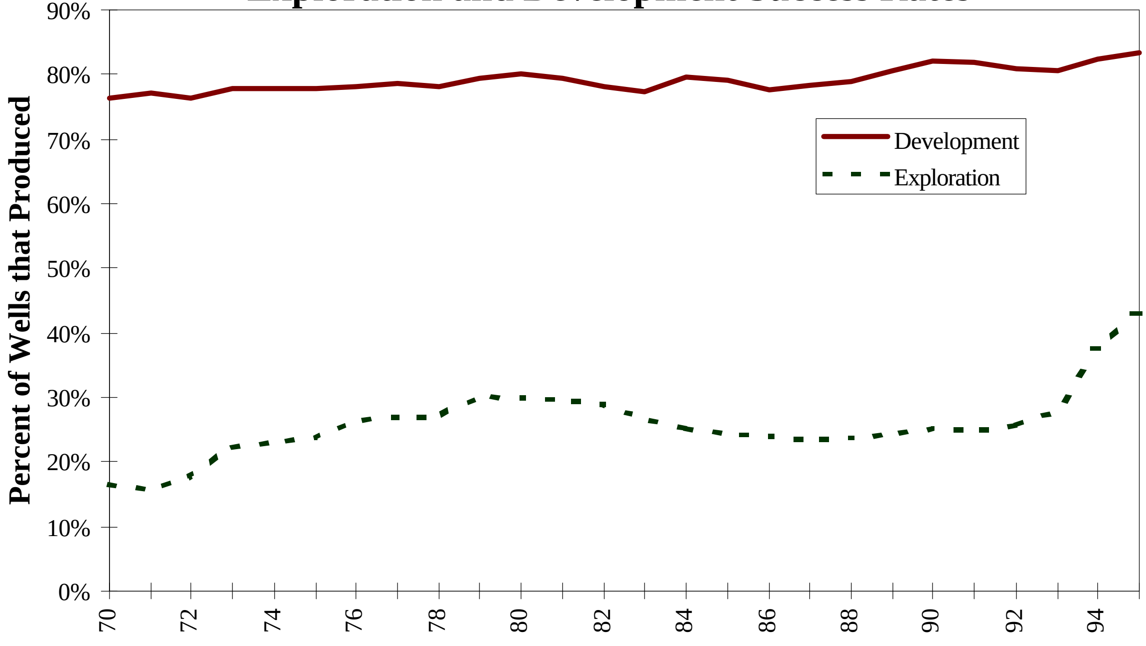
Figure 1-14
Production Divided by Additions to Reserves
(3 year moving average)



Note: Additions to Reserves are defined as the sum of discoveries, extension and revisions.

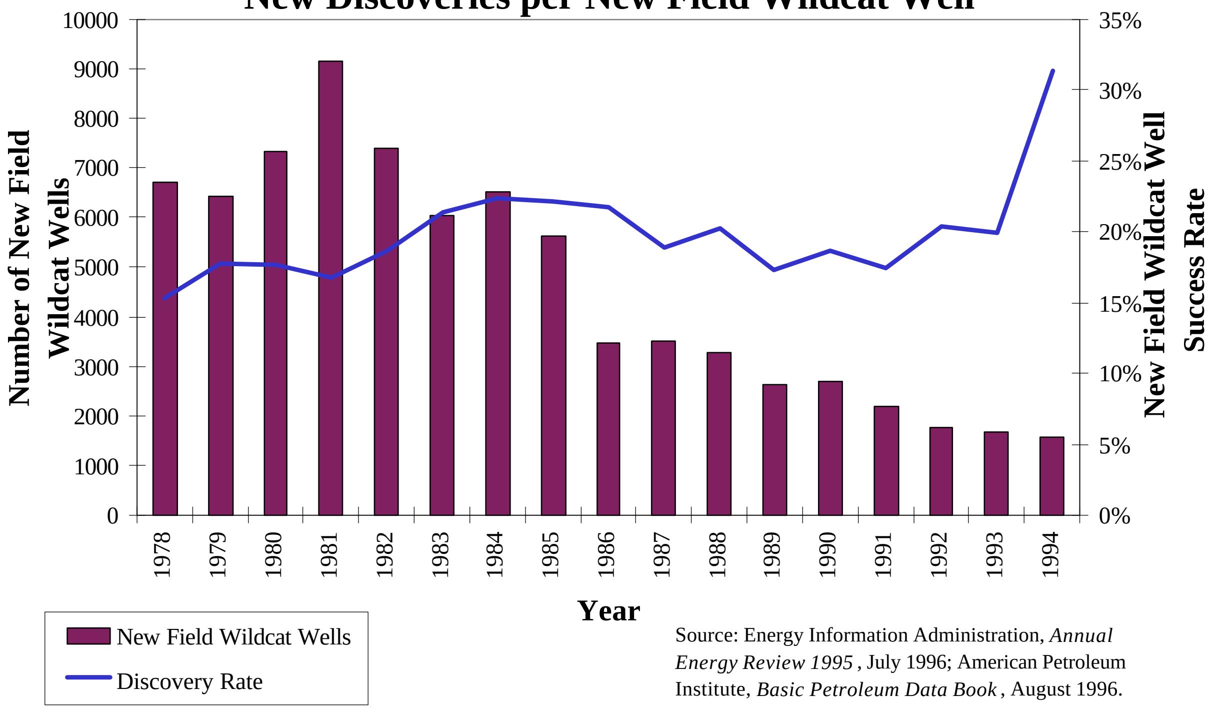
Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves Report*, Various Years; Energy Information Administration, A*nnual Energy Review 1995*.

Figure 1-15
Exploration and Development Success Rates



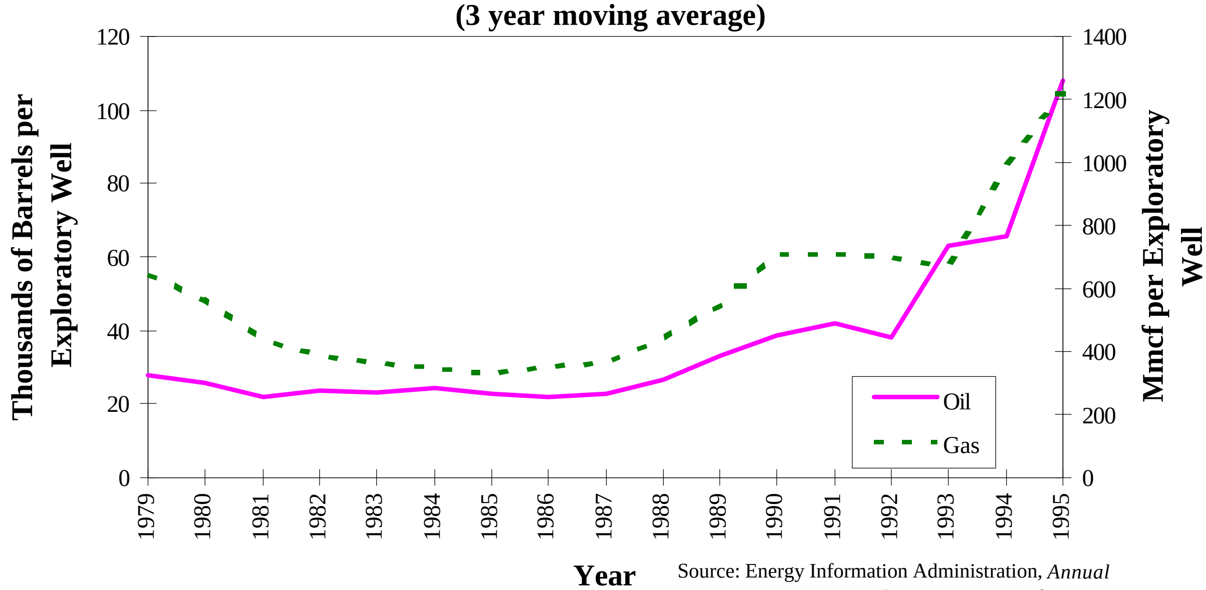
Source: Energy Information Administration, *Annual Energy Review 1995* , July 1996.

Figure 1-16
New Discoveries per New Field Wildcat Well



Source: Energy Information Administration, *Annual Energy Review 1995* , July 1996; American Petroleum Institute, *Basic Petroleum Data Book* , August 1996.

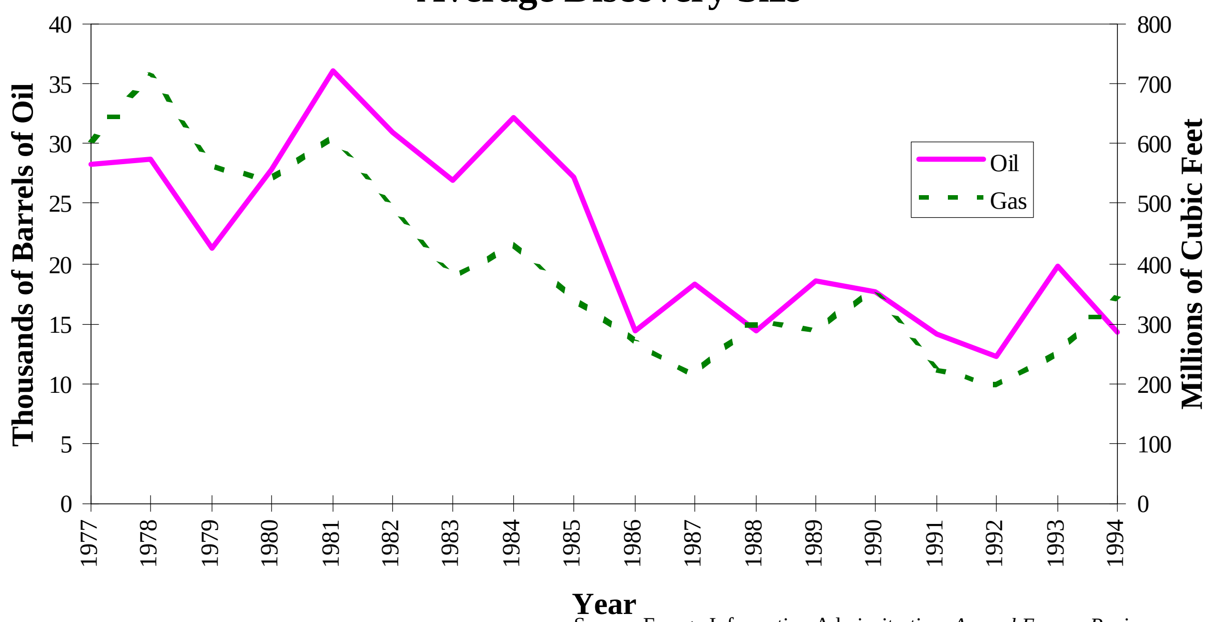
Figure 1-17
Oil and Natural Gas Finding Rates
(3 year moving average)



Note: Finding Rate is defined as the quantity of oil or gas discovered divided by the sum of exploratory wells, including oil, gas and dry wells.

Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996; Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, Various Years.

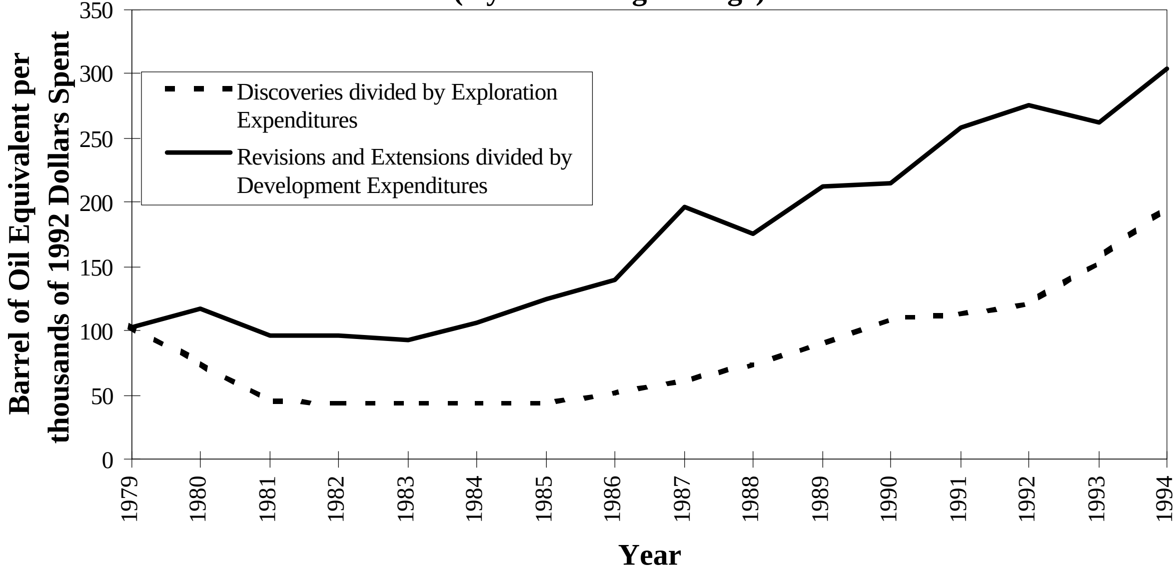
Fig. 1-18
Average Discovery Size



Note: The quanitity of hydrocarbon discovery is defines as the sum of discoveries in new fields, discoveries in oild fields and extensions.

Source: Energy Information Adminsitration, *Annual Energy Review 1995*; Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves Report*, Various Years.

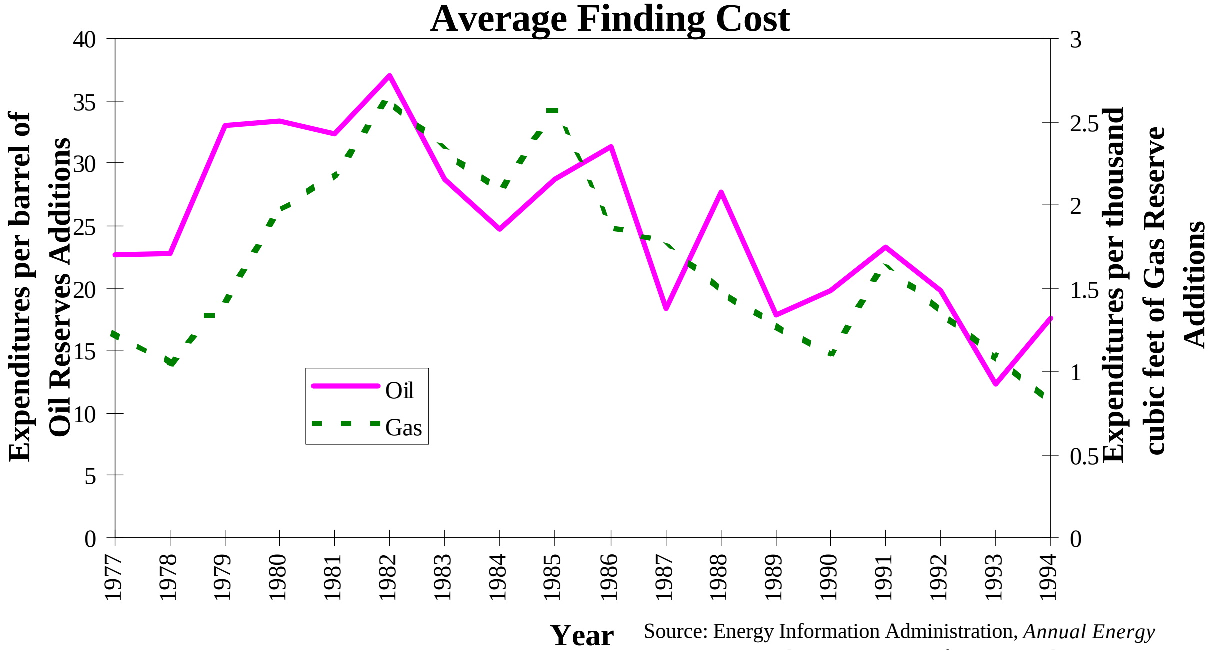
Figure 1-19
Yield Per Unit of Effort
(3 year moving average)



Note: Barrel of Oil Equivalent is defined as weighted sum, based on Btu's, of Oil and Natural Gas discoveries, revisions and extensions.

Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve Report,* Various Years; Energy Information Administration, *Annual Energy Review 1995,* July 1996.

Figure 1-20
Average Finding Cost



Note: Average Finding Cost is the ratio of exploration and development expenditures to discoveries, extensions and revisions.

Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996, Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves Annual Report*, Various Years.

Chapter 2

INSTITUTIONAL INFLUENCES ON PRODUCTIVITY

After the price of oil fell by half in 1986, firms in the petroleum industry came under intense pressure to find ways to increase profitability. Fundamental changes were required in the way that firms conducted their business, because oil and gas prices were not expected to rise again in the foreseeable future. The down-turn could not be weathered by the use of short term palliatives. Firms immediately responded to the fall in oil prices by reducing employment (as observed in Figure 1-14 above), but the changes soon went beyond downsizing. Another response was to develop and use new technologies that would lower the cost of adding new reserves, of which the three most important are described in subsequent chapters.[10] In addition, firms developed new strategies for restructuring their operations. These actions are the subject of this chapter.

Major petroleum companies (i.e., those integrated in all stages of supply) began to shift more of their exploration and development investments to targets outside of the U.S.[11] At the same time, many major companies sold their smaller and less profitable U.S. reserve holdings to independent firms. Both moves led to an increase in the share of exploration and development accounted for by independent firms. If independent firms follow different investment and development strategies compared to the majors, the shift in the mix of firms could account for a change in industry performance. The type of drilling, the size of discoveries, and the cost of reserve replacement could be affected.

At the same time that firms were reducing their upstream employment, they were also shifting more upstream activities to outside contractors. Rather than maintain their own drilling and seismic crews, petroleum firms turned to independent specialty firms to perform more of those services on a contract basis. If contractors perform more efficiently than insiders, the cost of finding and developing reserves would decline.

Finally, the structure of organizational decision-making within petroleum firms has become less hierarchical in recent years. Team decision-making has become the common mode of operation, where problem solving and investment decisions are made by the team rather than by the traditional management structure. The aim was to reduce the number of management personnel and to increase the quality of decision-making.

Each of the changes listed above has been motivated by the desire to reduce costs and increase profits. Working in the opposite direction has been the increasing cost of

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[10] "U.S. Firms Still "Restructuring, Cutting Costs under Oil Price Uncertainty," *Oil and Gas Journal*, vol. 92, no. 20 (May 16, 1994).

[11] Between 1986 and 1989, U.S.-based major oil companies doubled their exploration and development expenditures abroad, while their U.S. expenditures declined 14 percent. See Energy Information Administration, "Oil and Gas Development in the United States in the Early 1990's: An Expanded Role for Independent

environmental regulation. Firms have had to undertake increasingly costly measures to limit their impact on the environment. These measures inevitably lead to an increase in the cost of finding and developing reserves, and therefore to a reduction in the usual measures of productivity. However, it may be said that the regulations merely forced firms to internalize costs that were imposed on society before. From this perspective, reducing environmental damages does not necessarily lead to a reduction in productivity. On the contrary, a reduction in the amount of air and water pollution (which are the "bads" that result from the production process) relative to the production of oil and gas (which are the "goods" of the production process) may constitute an increase in productivity. Consequently, conventional measures of productivity may decline as a result of increased spending to reduce environmental damages, while corrected measures of productivity may show an improvement.

THE INCREASING IMPORTANCE OF INDEPENDENT PRODUCERS

In the decade following the collapse of oil prices in 1986, the share of exploration and development expenditures in the U.S. accounted for by independent firms increased from about 20 percent to nearly 50 percent of the total (see Figure 2-1, end of this chapter).[12] Investments by the majors declined during this period, while expenditures by independents nearly doubled. While the majors as a group continue to outspend the independents, the number of wells drilled by independents now exceeds the number drilled by the majors (see Figure 2-2, end of this chapter). The switchover for both exploratory wells and all wells occurred in 1993.

The independents' shares of both oil and gas reserves also increased steadily over the decade since 1985, as majors' reserves holdings declined while those of independents rose (see Figure 2-3, end of this chapter). The increasingly important role of independent producers in U.S. exploration and development raises questions about their effect on industry productivity, production costs, and other measures of industry performance.

The role of the independent producers in U.S. petroleum supply differs somewhat between oil and gas production, and between onshore and offshore activities. With regard to oil production, the majors dominate in deepwater and in Alaska, both of which are characterized by high development costs. The story is different onshore in the lower 48 states. Here, the volume of production accounted for by the majors declined steadily after 1986 and was eclipsed for the first time in 1992 by the volume production accounted for by the independents.[13] Part of the turnaround is accounted for by the sale of reserves by the majors to the independents. During 1989-1993, for example, independents purchased 500 million barrels of oil reserves from the majors, representing for 14 percent of independents' onshore reserve additions.[14] Nevertheless, the bulk of the reserve additions by independents

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[12] Majors are defined as large, integrated companies engaged in exploration, production, refining, and marketing of oil and gas worldwide. Independents are companies engaged in exploration and production, but not in all of the other stages of production. A list of the independent and major companies (92 in total) for which data are cited in this section is given in the appendix to this chapter.

[13] *Ibid.*, p.5.

[14] *Ibid.*

during this period, 2.9 billion barrels, were obtained through drilling, including new discoveries as well as revisions and extensions to existing reservoirs.[15]

With regard to gas production, the majors dominate offshore and the independents dominate onshore, though both of their majority shares declined over the last decade. Offshore gas production by the majors held steady at about 3 trillion cubic feet in the years following 1986, while that of independents increased from about 1 trillion cubic feet to close to 2 trillion cubic feet.[16] Until 1990, the increase in independents' production was supported by higher drilling and a reserve replacement rate in excess of 100 percent. For the next three years, independents replaced only 22 percent of their production, and net purchases of gas reserves from the majors exceeded the amount of new reserves added. [17]

The independents' extraction rate from offshore gas reserves, like that for oil noted above, increased sharply after 1986 (from 10 percent to 25 percent in 1993). The explanation for the rise in gas is the same as that for oil: higher cost reserves and higher debt leveraging as compared to the majors forced independents to increase their extraction rates in order to bolster cash flows.

The rate of extraction from existing reserves is not significantly different between majors and independents in recent years (see Figure 2-4, end of this chapter), but the majors responded to the oil price decrease in 1986 with a surge in the oil extraction rate. The comparative stability of the independents' behavior relative to the majors is surprising. If anything, one would expect the independents to be disadvantaged more than the majors by the decline in the price of oil and to compensate by increasing their extraction rate. One reason for this view is related to the sale of reserves by majors to independents. The reserves that were sold were typically higher cost than those retained by the majors, suggesting that extraction rates from these reserves would have to rise with the decline in the price of oil to make them economic. Another reason for expecting a higher extraction rate for the independents is that they rely more on external sources to finance their operations than the majors, and would have to maintain cash flow to repay their debt. These arguments do not appear to hold much weight, however.

The difference between majors' and independents' behavior is even more marked when the relationship between production and reserve additions is compared (see Figure 2-5, end of this chapter). The oil production rate for the majors exceeds the rate of additions to reserves and, except for one year, far exceeds the corresponding relationship for oil production by independents (even excluding outliers). The independents have been producing both oil and gas at a rate much closer to the in reserve replacement rate. The same can be said about the majors' production rate for gas. Because the differences extend over time, the majors were apparently following a strategy of not replacing their oil reserves as fast as their gas reserves. While the independents are more even-handed in the way they direct their exploration and development investments and, though they come closer to replacing their reserves as fast as they are produced, in general the stock of reserves is shrinking.

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15 *Ibid.*

16 *Ibid.*

17 *Ibid.*

Relative Performance of Majors and Independents

Measuring productivity on the basis of success rates (i.e., the percent of wells drilled that produce oil or gas), there is not a significant difference between the performance of the majors and the independents (Figure 2-6, end of this chapter).[18] Indeed, the success rates for exploratory wells are virtually identical for both groups, and they have been rising over the past decade. For development drilling, the majors' success rate is slightly higher than that of the independents, though the gap narrowed after 1990.

A significant difference arises between majors and independents regarding the payoff from exploratory drilling in recent years, however. Finding rates for both oil and gas (i.e., the volume of gas and oil discovered per exploratory well) are much higher for majors than for independents after 1991, although the difference was not especially pronounced before 1991 (Figure 2-7, end of this chapter). When oil and gas discoveries are combined according to their market values (Figure 2-8, end of this chapter), the difference in the performance of the majors and independents is even more dramatic. Clearly, the majors are achieving better results from their drilling efforts than the independents, and the difference appears to have widened in recent years.

The "yield per unit of effort" achieved by independents and majors, measured by the ratio of oil and gas reserves added (excluding acquisitions of reserves)[19] to the amount exploration and development expenditures, shows distinctly different patterns for oil (Figure 2-9, end of this chapter) than for gas (Figure 2-10, end of this chapter). The yield for oil has been rising sharply for the majors since 1986, while it has been relatively stagnant for the independents, though the yield ratio for independents is consistently higher than that for majors. Yields for gas, in contrast, are not significantly different between independents and majors, and have declined for both groups in recent years.

The inverse of the yield ratio is average finding cost. Figure 2-11 (end of this chapter) compares average finding costs for majors and independents, combining oil and gas into a single barrel of oil equivalent. The independents had generally lower finding costs than the majors prior to 1992, though the majors' costs declined sharply after 1986. One explanation for the reduction in majors' finding costs is related to their investment strategy in the U.S. The marginal cost of finding reserves is thought to be increasing at any point in time with respect to the amount of investment in exploration and development. Since the majors have been reducing their investments relative to the independents, it follows that average finding costs of majors should fall relative to that of the independents.

Relative Performance in Frontier Areas

We have seen that the finding rates and discovery-value per well are higher for majors than independents, but that average finding costs are lower for independents than majors.

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[18] Note that the source of data in this section differs from that in Chapter 1. Here the source is the Pennwell Company, which keeps records on 92 leading major and independent companies. The source of the data on the entire industry shown in Chapter 1 is the Energy Information Administration.

[19] Acquisitions of reserves are excluded from the calculations because they represent a transfer of ownership rather than the cost of finding reserves.

One explanation for this pattern is that, compared to the independents the majors are concentrating their attention on higher-risk, higher-payoff prospects such as deepwater drilling in the Gulf of Mexico. Certainly, the majors are more active in deepwater than the independents (see Figure 2-12, end of this chapter), and output per well rises sharply with water depth in the Gulf of Mexico (see Chapter 5). Nevertheless, the independents are becoming increasingly involved in the deeper waters of the Gulf. In addition, the independents appear to be no less inclined to use the latest drilling techniques. For example, Figure 2-13 (end of this chapter) shows that the independents use directional drilling as often as the majors in the Gulf.

An analysis of the relative performance of majors and independents operating in the Gulf of Mexico by Pulsipher and coauthors runs counter to the view that the majors are more risk-taking than the independents and more successful in finding new reserves.[20] Based on data for the ten year period from 1983 to 1992, the authors find that independent operators accounted for nearly 70 percent of all exploratory wells drilled on the OCS, and that exploratory drilling accounted for 50 percent of independents' total drilling effort compared to 22 percent for the majors. Consistent with the numbers in Figure 2-6 above for the whole country, they find that the majors have been moderately more successful than the independents in development drilling in the Gulf of Mexico. Contrary to Figure 2-6, however, they find that one-third of all exploratory wells drilled by independents found new reserves as compared to one-fourth for the majors.

Pulsipher and coauthors also estimate a model of drilling effort developed by Walls (1994) to test the responsiveness of drilling and reserve additions by majors and independents to economic and regulatory incentives. The majors turned out to be more responsive to increased economic incentives than the independents. In particular, an increase in the value of new reserves by 10 percent would prompt a 10.5 percent increase in drilling effort (i.e., footage drilled) by the majors and a 7 percent increase by the independents.[21] However, contrary to the author's observation that independents had a higher exploratory success ratio in the Gulf, but consistent with the figures in Figure 2-6, the model reveals no significant difference in drilling success ratios between majors and independents.[22]

In a separate study, Pulsipher and coauthors compare the safety and environmental performance of majors and independents involved in offshore oil and gas production.[23] Using Minerals Management Service data on accidents reported on offshore platforms between 1980 and 1994, the authors calculate individual safety scores for each operator that give higher weights to more serious accidents (accidents with no injuries receive a weight of

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[20] A. G. Pulsipher, O. O. Iledare, and R. H. Baumann, "An Analysis of the Role and Performance of Firms of Different Sizes in Petroleum Exploration and Development on the OCS," Center for Energy Studies, Louisiana State University, March 1996, p. 1.

[21] *Ibid.,* p. 38.

[22] *Ibid.,* p. 39.

[23] Allan Pulsipher, David Dismukes, Omowumi Iledare, and Dimitry Mesyanzhinov, "Comparing the safety and Environmental Performance of Offshore Oil and Gas Operators," Center for Energy Studies, Louisiana State University, December 1995.

1, accidents with injuries but not fatalities receive a weight of 5, and accidents resulting in fatalities receive a weight of 25). The summation of the safety scores for all operators tends to track the level of offshore activity, as affected in turn by changes in the price of oil. The safety score rises from about 500 in 1980 to a peak of 2100 in 1985, falls to less than 400 in 1986, and is generally less than 200 thereafter.[24] A regression analysis of the safety scores enables the researchers to account for variations due to the number of wells drilled and the type and age of platform in use, as well as variations that arise because of differences in the type of operator. The results of this analysis indicate that the independents had a marginally better safety record than the majors.

Conclusion

To conclude this section, there is some evidence to suggest that independents do follow different exploration strategies than the majors and are less involved in expensive deepwater operations. The result is that the majors earn a higher payoff from their exploration and development investments than the independents, and this result. The higher payoff is consistent with the higher risk associated with the majors' exploration strategy. However, there is no compelling reason to believe that the independents are any more or less productive than the majors. This conclusion follows whether productivity is measured in the conventional way on the basis of success rates and finding costs, or whether productivity is adjusted for their relative impact on the environment.

THE SHIFT TO CONTRACT SERVICES

Another aspect of industry restructuring in recent years has been increased reliance on contract services by firms engaged in exploration and development. Firms that specialize in seismic and drilling services are taking the place of company employees that perform the same services. The change is motivated by the desire to reduce the cost of exploration and development and to take advantage of the expertise gained by specialists.

It has been customary in the petroleum industry for firms to rely on outside companies to perform services related to exploration and development. In fact, the custom is so well established that these services are often provided in return for a share of the output, where the magnitude of the share is standardized according to the service provided. Thus, the shift to contract services in recent years is a change of degree rather than of kind.

The pressure to reduce operating costs led to the development of management strategies that focus resources on core activities, while outsourcing those deemed less essential to the company's business. This strategy is especially effective in reducing costs when applied to activities that are used intermittently, but which entail substantial overhead in labor and capital costs. Such is the case with drilling and seismic activities, as well as the services that support these activities.

The demand for seismic and drilling services is not uniform over time for each firm. Rather, the amount of activity waxes and wanes with the quality of prospects in the firm's inventory and the size of its exploration and development budget. An attempt to maintain the

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24 *Ibid.*, p. 4.

infrastructure required to satisfy even an average level of activity would mean that some crews would experience substantial downtime while waiting for the next job. In contrast, average operating costs would decline if these services were provided by independent contractors and the contractors could schedule the crews more efficiently than the production companies they work for. The efficiency gain is possible because the contractor can serve more than one production company and can smooth out the use of seismic and drilling crews across several firms.

Another motivation for outsourcing seismic and drilling services is related to the requirement for skilled labor associated with use of the latest seismic and drilling technologies. 3D seismic surveying, horizontal drilling, and deepwater development are all high-tech activities requiring highly trained specialists. Moreover, these technologies are being applied in new situations and in frontier areas where there is less experience to guide operations. Skilled personnel make fewer mistakes, anticipate more difficulties, and are better equipped to handle problems when they arise. Moreover, the specialized service contractors become effective partners in the development of new innovations. These characteristics have always been present in the supply of other specialty services, such drilling fluids, where production companies have relied on specialists to handle their routine needs and to develop new products for new situations.

Relying more on independent service contractors could have negative implications for productivity, however. When contractors do not share in the ownership of a prospect, they do not necessarily gain if the project is run any more efficiently or if the return on investment is large. The absence of incentives associated with a direct financial commitment could lead to higher rather than lower overall costs of production. To avoid this possibility, the industry commonly relies on production sharing to compensate contractors. Such arrangements instill an incentive to minimize costs over which the contractor has control.

For production sharing relationships to work properly, however, the contractor must have faith in the capability of the exploration and development company to chose the right prospects and make them payoff. Contractors cannot survive a long string of dry holes. Yet, the ultimate payoff depends on many factors over which the contractor has little control. By accepting a production sharing agreement, the contractor is also sharing the risk associated with all other activities that bring oil and gas to the market, not just exploration. From the perspective of the contractor, production sharing is more acceptable in low-cost, low-risk applications. Different arrangements are required for drilling in deep water or in construction of expensive drilling structures. The costs and risks are too high for even large contract firms to bear.

A potential conflict of interest arises in the use of production sharing arrangements to pay for seismic services. The conflict arises because the seismic firm could earn revenues from both its service activity and from its success in finding new deposits. When the contractor has such an arrangement with one production firm, it may lose credibility in providing seismic services to other production firms. In effect, the contractor becomes a competitor with potential customers and may use the information it obtains on behalf of its customers to improve its competitive position.

FROM HIERARCHICAL TO TEAM DECISIONMAKING

The major petroleum companies responded to the decline in oil prices after 1986 by altering their internal management structures. The changes have an analogue in traditional productivity concepts, where the amount of output is related to the amount of input by a production function that is characterized by the type of technology employed. In the management context, inputs get converted into outputs by a process that may be termed the "technology of management." A change in technology can lead to an improvement in productivity in the sense that more and better management decisions are made with the same or fewer inputs. An improvement in management productivity presumably (but not necessarily) leads to improvements in productivity at all stages of production. Better decisions regarding the level and use of exploration and development expenditures might be expected to lead to better success rates and finding rates, larger additions to reserves per unit of effort, higher average discovery sizes, and lower average finding costs, but there has been no evidence to date regarding quantitative results.

The principal change in the technology of management is the introduction of horizontally-organized problem solving teams in place of the traditional vertical corporate structure. Decisions are to be made within the team rather than flow down from above. One of the expected benefits of this structure is that it makes the firm more responsive to changes in opportunities and problems and more creative in finding new approaches. Decisions can be made more quickly by those immediately dealing with the problem, as long as authority accompanies responsibility in making decisions. Decentralized management aims at focusing responsibility at the lowest possible level. According to one firm, "the people most familiar with the business are making the key decisions with a minimum of technical and management review."[25]

The teams include representatives from all areas of the company with the expertise required to solve a particular problem or to make an specific investment recommendation. By making employees at all levels an equal part of the decision process they are expected to take an "ownership" interest in the outcome, and employees see more clearly the role they play in corporate decisions.

Moreover, the team concept encourages information sharing among experts from different fields within the company. When experts are compartmentalized by field of expertise in a division structure, information has a tendency to stay within the division. Improvements in production techniques may be understood and appreciated within a division but not across other parts of the firm. By working together in a team setting, the experts are encouraged to share their knowledge with other members of the team. Presumably, experiences will be shared across teams as well, although this result is less certain.[26]

Along with information sharing comes receptivity to new ideas. The team concept is thought to encourage creativity and innovation in problem solving. Outmoded ideas are harder to support when they are subjected to critical analysis from several different

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[25] "Chevron Restructuring U.S. Upstream Unit," *Oil and Gas Journal,* vol. 88, no. 9 (February 26, 1990).

[26] In talking with technical experts, I have learned that papers are presented to professional societies as much for the purpose of informing professional colleagues within the firm as for informing colleagues from other firms.

perspectives. Similarly, a range of perspectives is useful when looking for new approaches. A new approach that has taken hold at Amoco is the application of risk management techniques. Experts evaluate the payoffs from alternative exploration strategies in probablistic terms to focus efforts in directions where the company has a comparative advantage. This approach is regard as a reason for the shift in terms of 3D seismology and in exploratory success at Amoco after 1990, as described further in Chapter 3.

Finally, the team concept reduces the need for management personnel. As the organizational structure is flattened, the number of managers required to occupy each level of the pyramid is reduced. Fewer levels equals fewer managers. One theory in support of this approach is that less emphasis on management details results in more emphasis on substantive issues. This shift in emphasis, if it is successful, is particularly appropriate with regard to exploration and development decisions, given the complexity of the geophysical concepts encountered and the sophistication of equipment usually employed.[27] Presumably, the opinions of technical staff would weigh heavier in decisions made by the team approach compared to traditional hierarchical management.

British Petroleum Company has been particularly aggressive in decentralizing its corporate decisionmaking process, particularly with regard to upstream activities.[28] BP's exploration affiliate (BPX) promotes self-organizing, self-empowering teams to make development decisions. The teams have their own budget, select their own leader, and are responsible for their own performance. For example, one team decided to sell small fields that have been on the books for many years and that are continually shelved in favor of other, easier projects.[29] The team exercised its authority to follow through with the decision to sell and, apparently, upper management acquiesced to the decision.

THE RISING COST OF PROTECTING THE ENVIRONMENT

Not so long ago the petroleum industry, like all other business, was not burdened with government regulations designed to protect the environment. Over the years a multitude of environmental laws at both the state and federal level have been enacted that affect the costs associated with petroleum exploration and production. Compliance with the laws requires some combination of a change in production methods, investment in pollution mitigation equipment, and elimination of some activities. Inevitably, these requirements lead to an increase in the costs of production and, when measured the usual way on the basis of marketed inputs and outputs, a reduction in industry productivity.

The proper way to view the productivity implications of environmental regulations is to broaden the measurement of outputs to include environmental "

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[27] Reportedly, firms have been responding to the higher skill requirements in exploration and development by placing more emphasis on hiring high quality engineers and scientists at this level compared to downstream functions.

[28] Roger Vielvoye, "BP's Robert Horton Overseas Broad Change in Firm's Corporate Culture," *Oil and Gas Journal*, vol. 88, No. 50 (December 10, 1990).

[29] *Ibid.*

pollution) as well as marketed "goods" (e.g., new reserves added).[30] Environmental bads have a negative contribution to productivity that offset the positive contribution of marketed goods. The combination of bads and goods yields a smaller number than the measure of goods alone, so that the numerator in the productivity calculation is also smaller. Thus, ignoring the environmental consequences of petroleum exploration and development yields an overestimate of productivity.

Environmental regulation forces firms to increase the number of inputs (i.e., activities required to mitigate pollution) used in production, possibly reduces marketed output (e.g., if exploration is banned in some areas), and reduces environmental bads. Taking into account the changes in both goods and bads, the numerator could go up or down in the productivity calculation. If the change is positive, productivity could benefit from environmental regulation even if more inputs are required to produce the same amount of output as before the regulation. If the regulations are imposed only when the social benefits exceed the social costs, presumably they lead to an increase rather than a decrease in productivity.

Despite this more sophisticated way to measure productivity, all of the measures used here rely on marketed inputs and outputs alone. Thus, our measures may give an exaggerated impression of the effect of changes in environmental regulations on productivity. Since environmental regulation has become increasingly restrictive and increasingly expensive over time, the practical implication is that productivity has been rising faster than our measures convey.

The remainder of this section will briefly overview some of the most important regulations affecting petroleum exploration and development, with particular emphasis on those that have been imposed in the last ten years.[31] No attempt will be made to estimate the cost of these regulations to the industry, nor their effect on productivity.[32]

Perhaps the single most important environmental restriction affecting petroleum exploration and development is the ban on these activities in several areas within the U.S., particularly in areas with significant known petroleum deposits such as the Arctic National Wildlife Refuge, offshore California, and the Gulf of Mexico off the coast of Florida. These restrictions undoubtedly raise costs and lower measured productivity in exploration and development compared to what they would be without any restrictions, though it cannot be asserted that they reduce true productivity for the reasons just given.[33] In any case, for

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[30] Robert Repetto, Dale Rothman, Paul Faeth, and Duncan Austin, *Has Environmental Protection Really Reduced Productivity Growth?* (Washington, DC: World Resources Institute, 1996).

[31] This information is drawn from Terry G. Gregston, *An Introduction to Federal Regulations for the Petroleum Industry* (Austin, TX: Petroleum Extension Service, University of Texas, 1993); and George H. Holliday, *Environmental/Safety Regulatory Compliance for the Oil and Gas Industry* (Tulsa, OK: Pennwell Publishing Co., 1995).

[32] There are no estimates in the literature of the effect of environmental regulation on productivity in petroleum exploration and development. Estimates that are available focus on petroleum refining. See, for example, W. B. Gray and R. J. Shadbegian, "Pollution Abatement Costs, Regulation, and Plant-Level Productivity," National Bureau of Economic Research, working paper no. 4994, January 1995.

[33] The restrictions are less important to industry performance if productivity measures are adjusted to include the negative environmental implications of resource development along with the positive contribution of expanding resource supply. Whether the negatives outweigh the positives is highly subjective, though society has made a determination through the political process.

purposes of our investigation into the changes in productivity that have occurred over the last ten years, these drilling restrictions have not been a factor because they have been in place for a longer period of time.

The Clean Air Act, and especially the Clean Air Act Amendments of 1990, affect petroleum exploration and development operations by controlling air contaminants from combustion sources and hazardous air pollutants. Some of the emissions that are affected include emissions from mixing drilling muds; exhausts from diesel engines and boilers; emissions from gas flaring; volatile organic compounds released during the storage, transportation, and treatment of oil and gas; and hydrogen sulfide emissions from drilling for or producing oil and gas, as well as from treatment facilities.

One of the more important changes in the regulation resulting from the Clean Air Act Amendments of 1990 concerns the number of hazardous air pollutants that are regulated. Prior to 1990, the U.S. Environmental Protection Agency set national emissions standards for 7 hazardous pollutants; after 1990, the list expanded to 189. Moreover, prior to 1990, benzene, a chemical commonly found in petroleum, was on the list but petroleum exploration and production was exempted; after 1990, the exemption was lifted.

The Clean Water Act of 1977 regulates the discharge of pollutants into surface waters of the U.S. Some of the discharges associated with exploration and development that are affected include: drilling fluids, drill cuttings, produced water, and blowout preventer fluid. Regulations under the Act have been tightened in recent years to reduce discharges in coastal waters.

The Oil Pollution Act of 1990 is an extension of the Clean Water Act that requires establishment of the capability to respond to oil spills, increases spill liabilities, and creates a trust fund to help clean up spills. The Act applies to storage tanks, ships and loading facilities, offshore platforms, and onshore and offshore pipelines.

The Safe Drinking Water Act of 1974, in addition to controls imposed on water systems that serve the public, also regulates various kinds of injection wells that are associated with petroleum exploration and production. For example, injection wells are used to dispose of produced waters into depleted oil formations, inject water from production operations back into the producing zone, inject fluids for enhanced recovery, and store hydrocarbons. To reduce contamination of drinking water from these operations, EPA has developed regulations for plugging abandoned wells, installing casing and cement, the types of substances that can be injected, and the volume and pressures that can be injected. These regulations are substantially unchanged in the last ten years.

The Toxic Substances and Control Act of 1977 regulates the manufacture, use, and disposal of new and existing chemical substances. The Act primarily affects the downstream segments of the petroleum industry because substances “naturally occurring” are generally exempt. For example, benzene, toluene, and xylene are exempt as naturally occurring in gas and oil. There are complications, however. For example, the physical separation of natural gas liquids from natural gas is exempt as naturally occurring, while the chemical separation of the same liquids is considered unnatural and is covered by the Act. Again, no major changes in the Act have occurred in the last ten years.

The Resource Conservation and Recovery Act of 1976 controls the disposal of hazardous wastes (and encourages the development of alternative energy sources). In 1980, the Act was amended to exempt wastes "uniquely associated" with petroleum exploration and production.[34] In particular, exempted wastes include those associated with the location of oil and gas deposits, the extraction of oil and gas from the ground, and the removal of impurities as part of primary field operations.[35] The exemption is a major financial benefit to petroleum exploration and production. No important changes in the Act have occurred in the last decade, though the exemption is a target of environmental groups.

The Outer Continental Shelf Lands Act of 1953 authorizes the secretary of the interior, through the Minerals Management Service, to grant mineral leases and regulate oil and gas activities on the Outer Continental Shelf. The regulations require an exploration plan, and later a development and production plan, that must include measures to protect the environment. Lessees are required to use best available and safest technology to minimize the potential for uncontrolled well flow. Regulations govern the design, fabrication, use, and disposal of offshore platforms to assure the safety and protection of the human and marine environments. Specific requirements are also imposed on pipeline transportation. Some differences in the regulations apply to offshore Alaska to cover permafrost, subfreezing temperatures, and severe oceanographic conditions.

This list of environmental regulations that affect the industry is by no means complete. Also pertinent are the Migratory Bird Treaty Act, the Endangered Species Act, the Alaska Environmental Acts, the Coastal Zone Management Act, the Deepwater Port Act, the Federal Land Policy and Management Act, and the Federal Oil and Gas Royalty Management Act. The list also excludes state land-use and environmental regulations.

CONCLUDING REMARKS

Among the various institutional changes that have occurred in the petroleum industry over the last decade, none have produced unambiguous changes in industry productivity, even though individual firms may have been affected. Independent firms are on the whole no less productive than their major counterparts, even though their investment strategies differ. Similarly, no substantial changes in environmental controls have occurred in the last decade, although a steady tightening of regulations affecting exploration and production has occurred.

More elusive are the implications of outsourcing and management restructuring. According to one company president, the major petroleum company of the 21st century "will be a highly decentralized company with each of its segments operating as autonomous entities. It will have outsourced as much as 40 percent of its activities. It will have far fewer employees; perhaps as little as one third of its professional staff of today."[36] This describes what has taken place already within most firms in the industry. Has the result been all that beneficial? Not to all observers. According to one management consultant, the industry does

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[34] Similarly, petroleum and natural gas spills are exempted from the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (better known as Superfund).

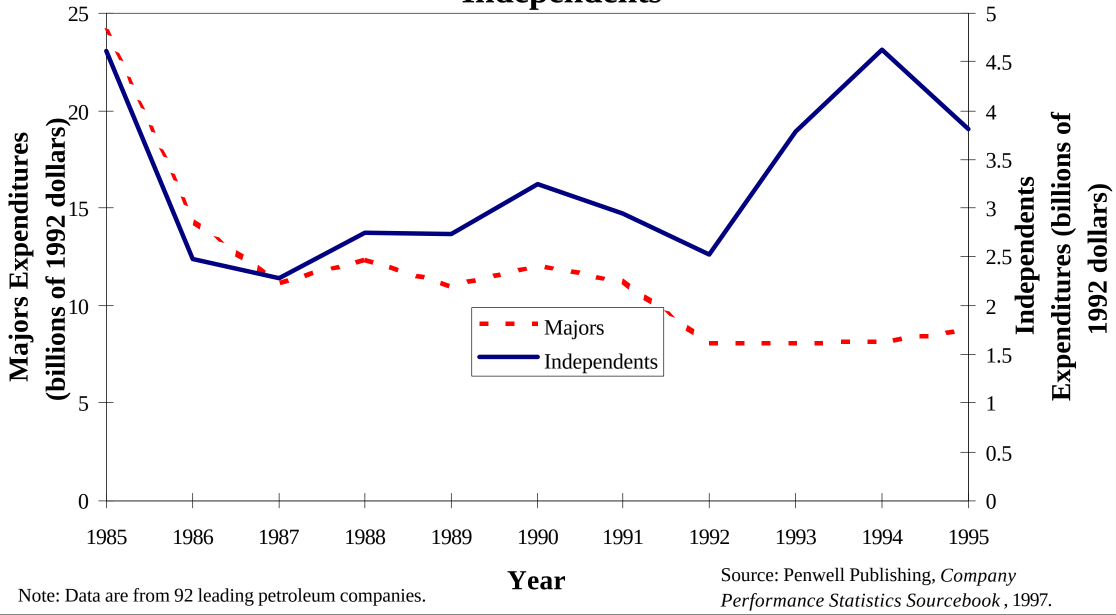
[35] Among the few wastes not exempt from the Act are unused fracturing fluids, used lubricating oils, pipeline wastes and related pits, waste compressor oil, and caustic or acid cleaners.

[36] P.J. Carroll, President of Shell Oil Company, "How Oil Companies Must Adapt to Survive in 2000 and Beyond," *Oil and Gas Journal*, vol. 93, no. 47 (November 20, 1995).

not comprehend the impact of restructuring: “the need to cut staffs, to sell assets, to consolidate departments, and to slash the budget has taken precedence over any effort at understanding the big picture.”[37]

[37] J.P. Chevriere, “After the Cost-Cutting,” *Oil and Gas Journal*, vol. 55, no. 10 (January 9, 1995).

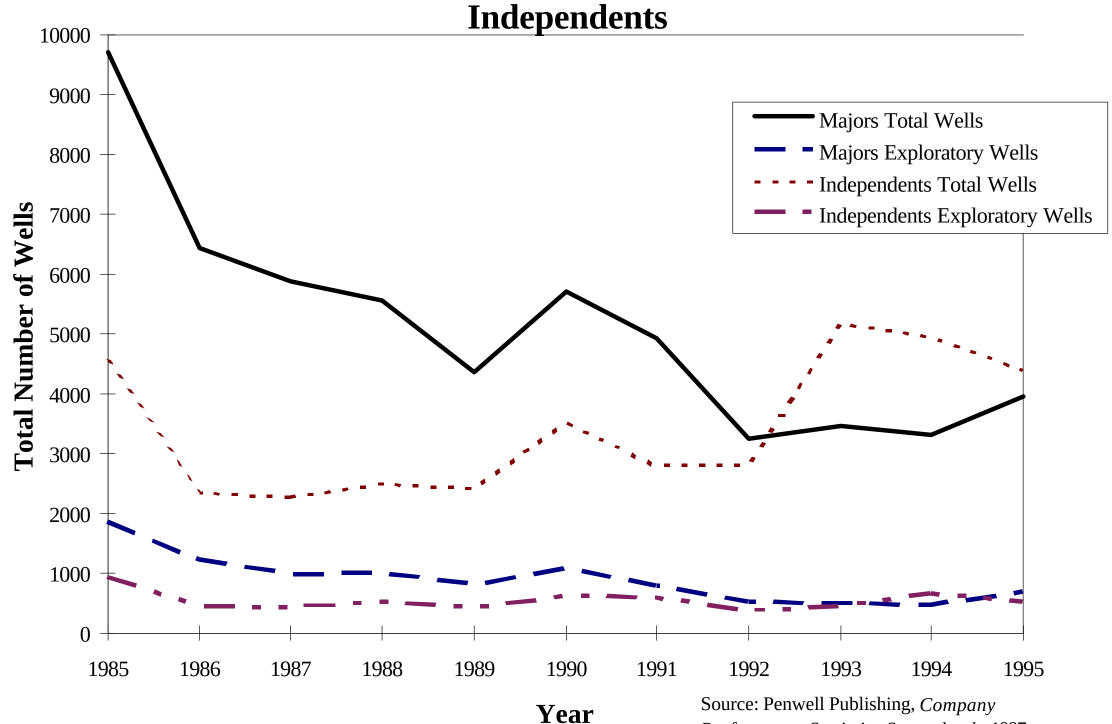
Figure 2-1
Exploration and Development Expenditures of Majors and Independents



Note: Data are from 92 leading petroleum companies.

Source: Penwell Publishing, *Company Performance Statistics Sourcebook*, 1997.

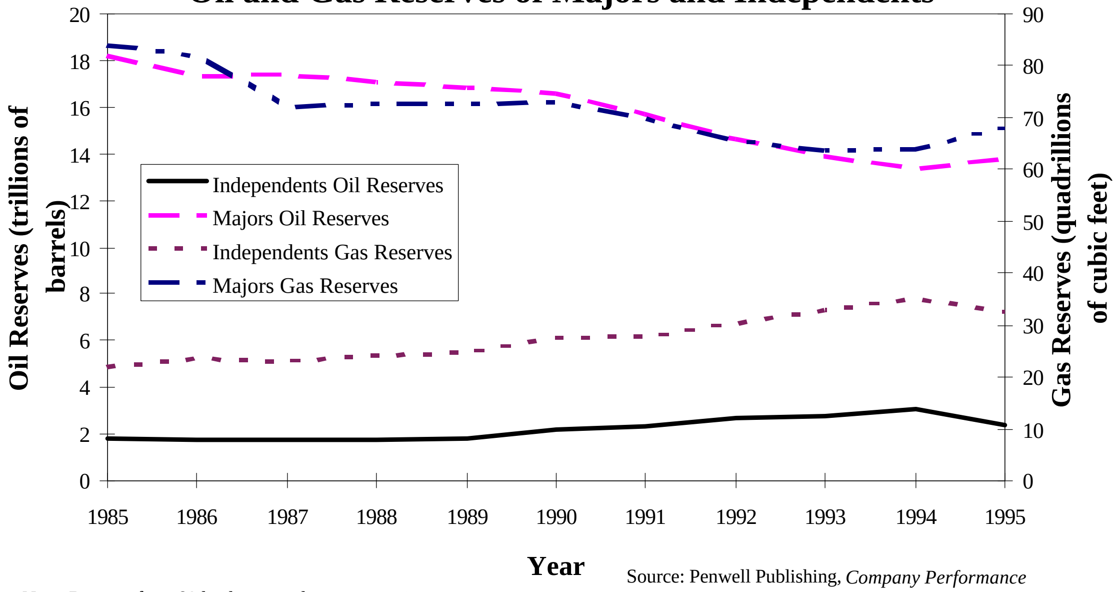
Figure 2-2
Exploration and Total Wells Drilled by Majors and Independents



Note: Data are from 92 leading petroleum companies.

Source: Penwell Publishing, *Company Performance Statistics Sourcebook*, 1997

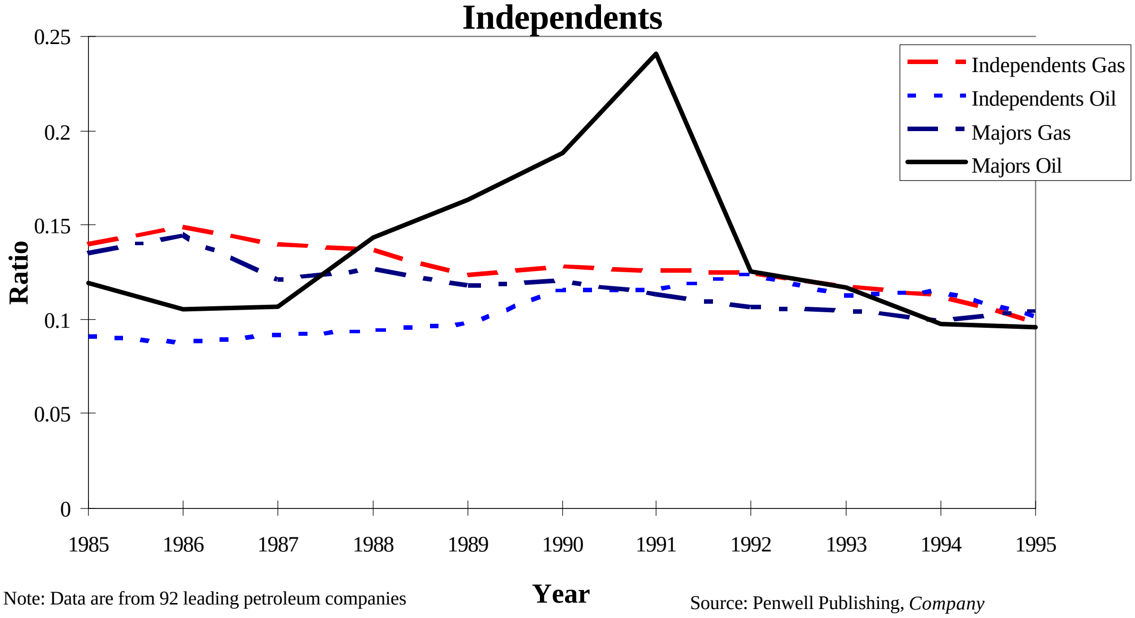
Figure 2-3
Oil and Gas Reserves of Majors and Independents



Note: Data are from 92 leading petroleum companies.

Source: Penwell Publishing, *Company Performance Statitistics Sourcebook*, 1997.

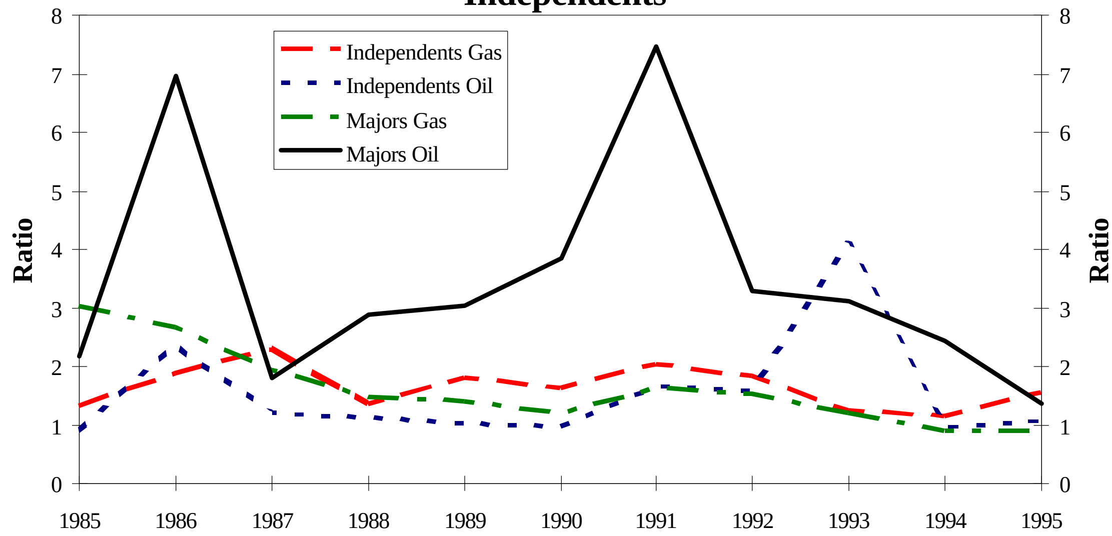
Figure 2-4
Production divided by Total Reserves of Majors and Independents



Note: Data are from 92 leading petroleum companies

Source: Penwell Publishing, *Company Performance Statistics Sourcebook*, 1997.

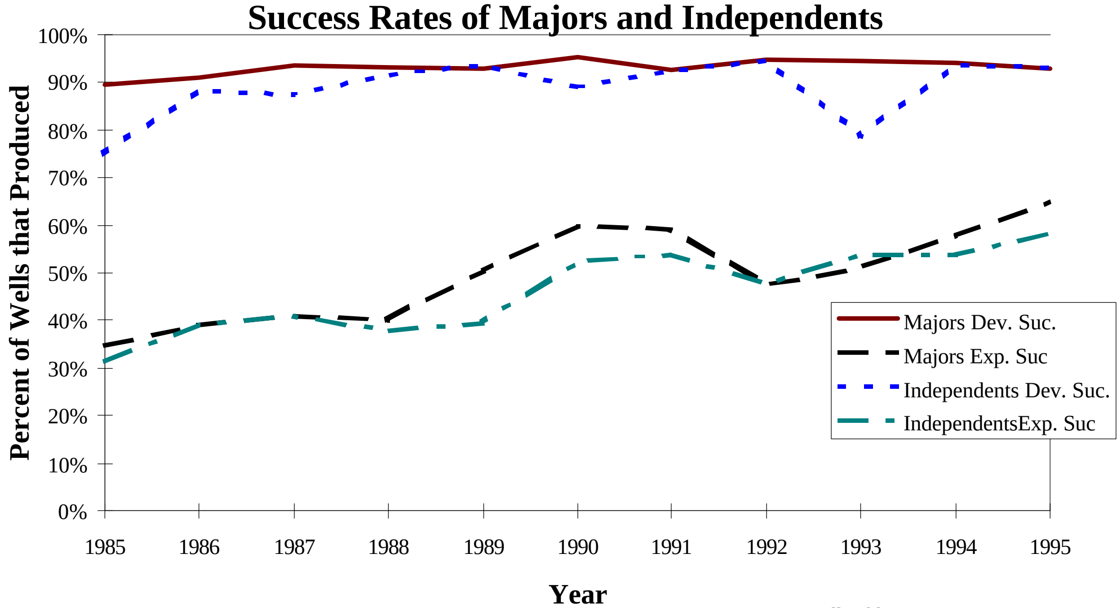
Figure 2-5
Production Divided by Additions to Reserves of Majors and Independents



Note: Additions to reserves include discoveries, extensions and revisions. Data are from 92 leading petroleum companies.

Source: Penwell Publications, *Company Performance Statistics Sourcebook*, 1997.

Figure 2-6
Success Rates of Majors and Independents



Note: Data are from 92 leading petroleum companies.

Source: Penwell Publications, *Company Performance Statistics Sourcebook*, 1996.

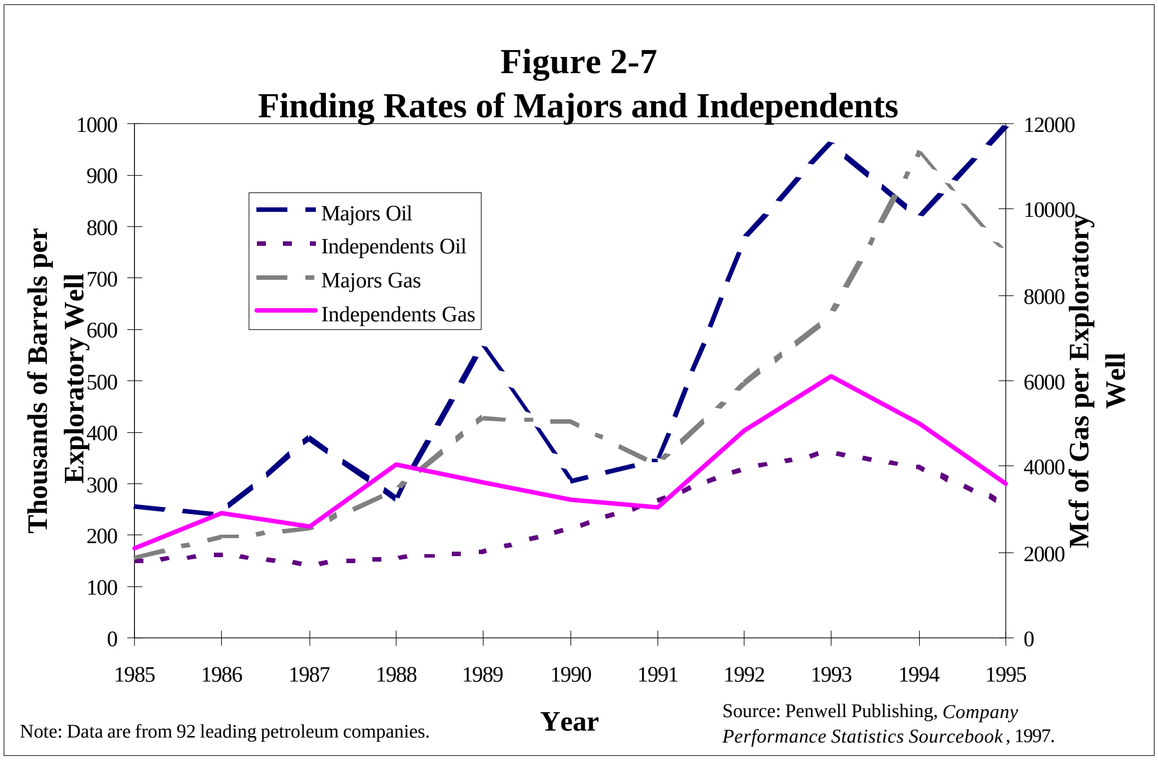


Figure 2-7
Finding Rates of Majors and Independents
Thousands of Barrels per Exploratory Well
Mcf of Gas per Exploratory Well
Majors Oil
Independents Oil
Majors Gas
Independents Gas
0
100
200
300
400
500
600
700
800
900
1000
0
2000
4000
6000
8000
10000
12000
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Year
Note: Data are from 92 leading petroleum companies.
Source: Penwell Publishing, *Company Performance Statistics Sourcebook*, 1997.

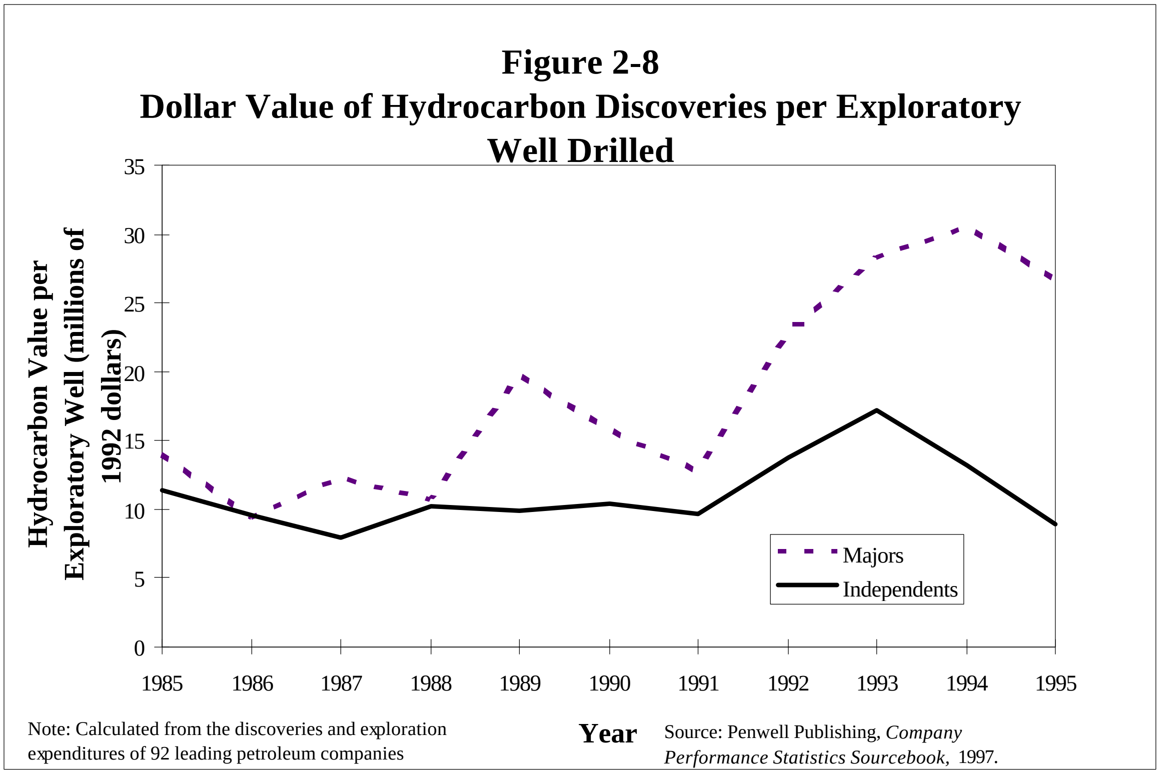
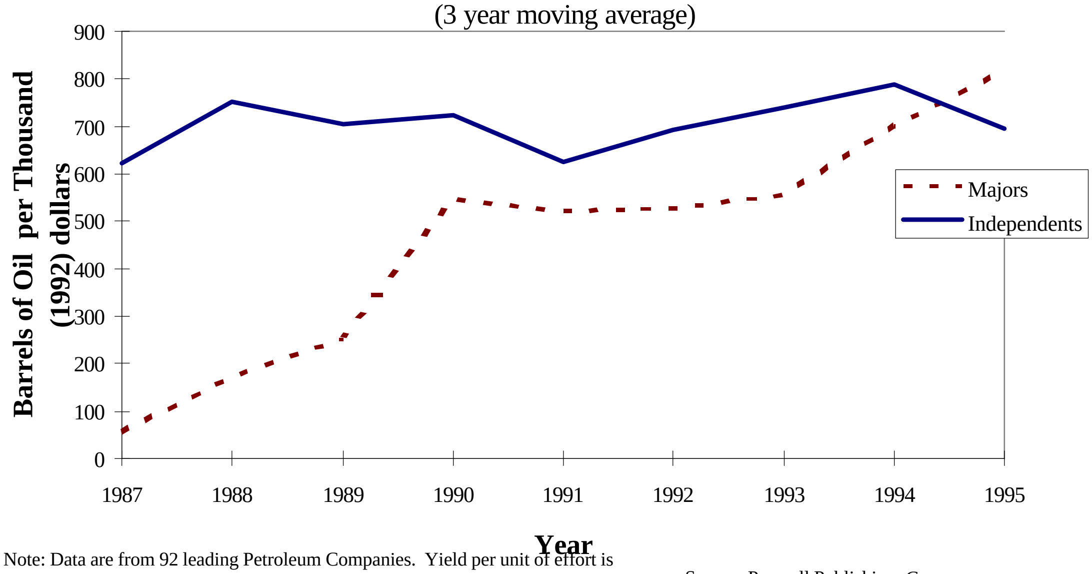


Figure 2-8
Dollar Value of Hydrocarbon Discoveries per Exploratory Well Drilled
Hydrocarbon Value per Exploratory Well (millions of 1992 dollars)
0
5
10
15
20
25
30
35
Majors
Independents
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
Year
Note: Calculated from the discoveries and exploration expenditures of 92 leading petroleum companies
Source: Penwell Publishing, *Company Performance Statistics Sourcebook,* 1997.

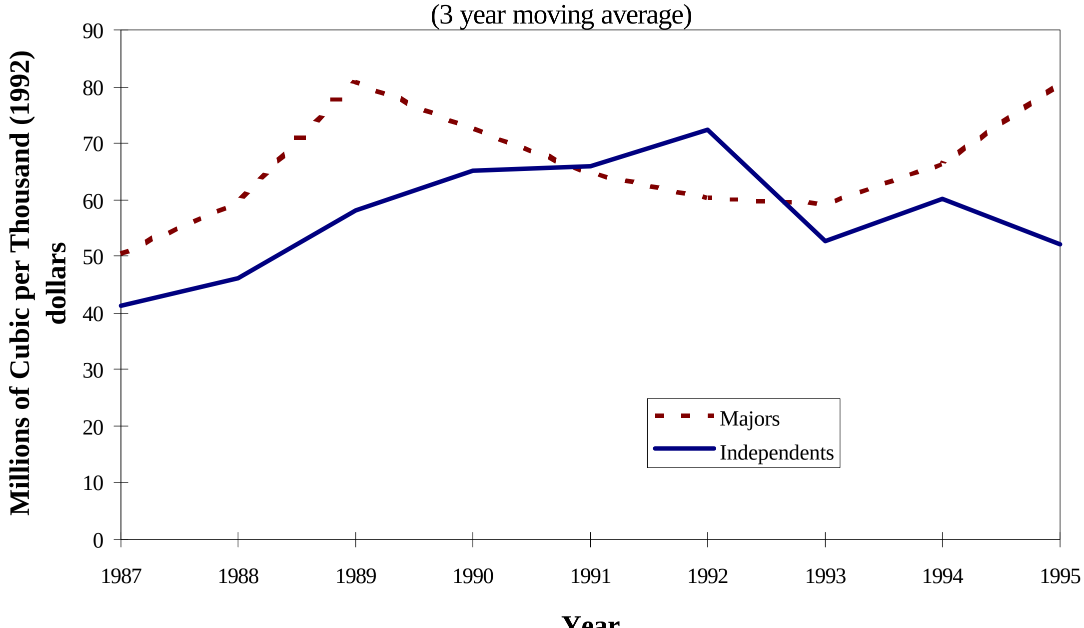
Figure 2-9
Yield per Unit of Effort: Oil
(3 year moving average)



Note: Data are from 92 leading Petroleum Companies. Yield per unit of effort is defined as the sum of discoveries, extensions and revisions of oil fields divided by the sum of exploration and development expenditures.

Source: Penwell Publishing, *Company Performance Statistics Sourcebook*, 1997.

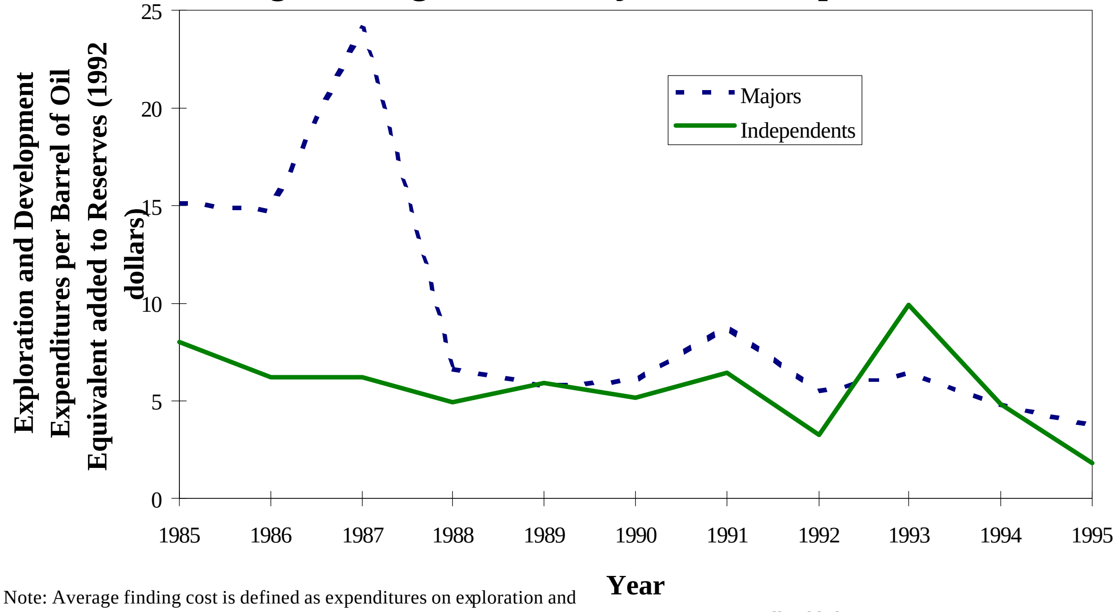
Figure 2-10
Yield per Unit of Effort: Gas
(3 year moving average)



Note: Data are from 92 leading Petroleum Companies. Yield per unit of effort is defined as the sum of discoveries, extensions and revisions of gas fields divided by the sum of exploration and development expenditures.

Source: Penwell Publishing, *Company Performance Statistics Sourcebook* 1997.

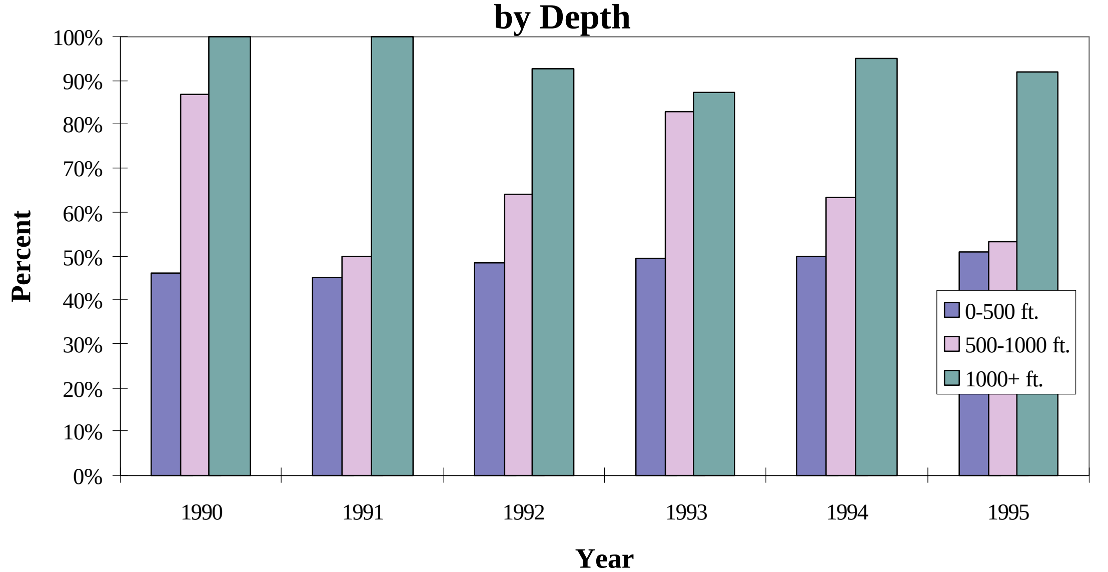
Figure 2-11
Average Finding Costs of Majors and Independents



Note: Average finding cost is defined as expenditures on exploration and development divided by the sum of discoveries, extensions and revisions. Data are from 92 leading petroleum companies

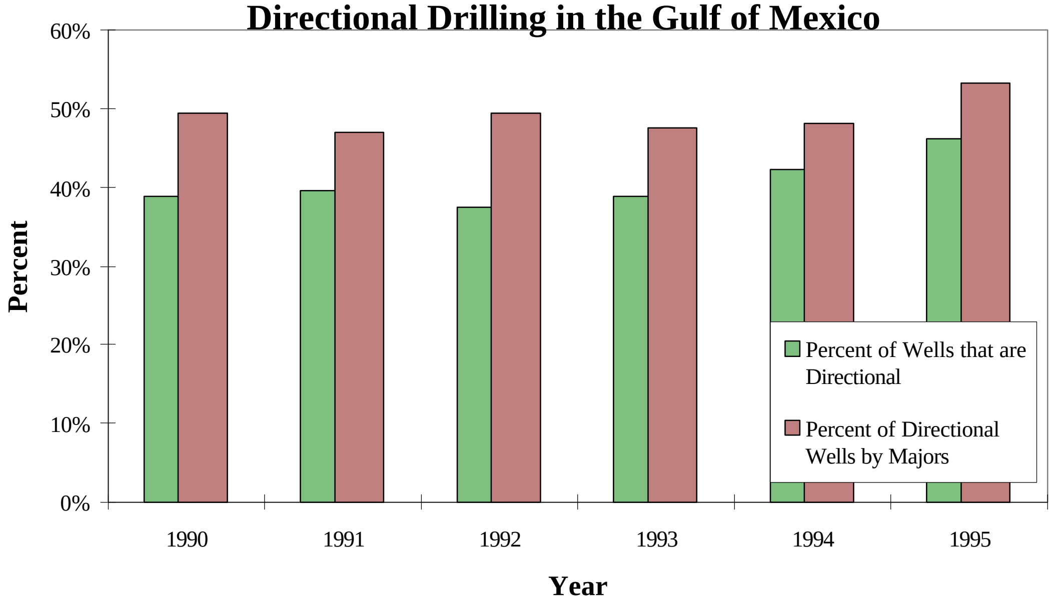
Source: Penwell Publsihing, *Company Performance Statistics Sourcebook*, 1997.

Figure 2-12
Percent of Wells in the Gulf of Mexico Drilled by Majors, by Depth



Source: Minerals Management Service, Gulf of Mexico Region. *All Well Completion Data, Detailed List, 1990-1995* [electronic file].

Figure 2-13
Directional Drilling in the Gulf of Mexico



Source: Minerals Management Service, Gulf of Mexico Region.
All Well Completion Data, Detailed List, 1990-1995 [electronic file].

Chapter 3

3D SEISMOLOGY: PRODUCTIVITY AND RESOURCE IMPLICATIONS

This is the first of three chapters that discuss the implications of recent advances in exploration and development technologies. We begin by describing the fundamentals of 3D seismology, including how 3D differs from the older 2D technology, and how the new technology is used. The following sections analyzes the implications of 3D seismology for industry productivity and for resource development.

3D SEISMIC TECHNOLOGY

Reflection seismology uses sound waves propagated into the earth and reflected back to the surface to infer the structure and properties of subsurface rock layers. The technique has been used in the search for hydrocarbons since the 1920s, but a revolution has occurred, largely since 1985, with the development of three-dimensional (3D) seismic surveying methods.[38] Compared to the earlier two-dimensional (2D) methods, 3D seismology provides a better picture of the composition and structure of subsurface rock layers. The higher quality images greatly improve the ability to locate new hydrocarbon deposits, to determine the characteristics of reservoirs for optimal development, and to help determine the best approach for producing a reservoir.[39] This new technology makes it possible to find smaller deposits than possible with 2D seismology, and to identify deposits in locations, such as beneath salt layers, where it was impossible to discern their presence before. Similarly, 3D seismology makes it possible to locate isolated traps in older, sometimes abandoned, fields that would otherwise be left behind. The extent of the improvement from 2D to 3D technology has been compared to the improvement in Magnetic Resonance Imaging over x-rays in medicine. This section describes this new technology and what it can do.

Seismology is the study of the properties of sound waves to determine subsurface geologic structure and rock properties. Sound waves are generated at specific locations on the earth's surface, or in water, that travel into the earth. Part of the energy is reflected back to the

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[38] In addition to reflection surveys, gravity surveys and magnetic surveys are also used in the search for hydrocarbon deposits. With a gravity survey, a measuring instrument is passed over the earth's surface to measure minute variations in gravitational force. High gravity measurements indicate the presence of high density rock that has been raised nearer to the surface, such as a buried anticline, while a low gravity measurement indicates the presence of a low density rock such as a salt dome. Magnetic surveys, in contrast, look for distortions (from normal) in the earth's magnetic field to identify magnetic anomalies that might be caused by arches and other structural traps in overlying sediments. Magnetic surveys are not considered very reliable as a primary exploration tool, but are used as a supplement to seismic and gravity surveys.

[39] A good source for non-specialists is Mamdouh R. Gadallah, *Reservoir Seismology: Geophysics in Nontechnical Language* (Tulsa: Pennwell Books, 1994). A brief overview is given by Robert Haar, "Three Dimensional Seismology--A New Perspective," in Energy Information Administration, *Natural Gas Monthly* (December 1992).

surface (hence, "reflection" seismology) whenever it passes through a discontinuity such as the interface between two rock layers of different densities. The energy is reflected back to receivers on the surface called geophones (on land) or hydrophones (in water), where the reflected waves are converted to electrical signals that can be recorded for subsequent analysis. The receivers measure the arrival time for the sound waves, as well as their amplitude and frequency. Timing information is used to determine the location of subsurface structures, while amplitude and frequency are used to determine the composition of rock layers.

The methods of analysis and interpretation of the data are as much art as they are geologic science, but this is the stage where the advances in technology have been most important. An enormous amount of data is required to yield a high-resolution image of the subsurface, and 3D methods require much more data than 2D methods. What held back the advent of 3D technology was the complementary development of sufficient computing power and accompanying analytical software. Once parallel computing arrived in 1985, it did not take long for the development of improved sound receivers, data handling and transmission equipment, and analytical models to take advantage of the innovation. More time was required to gain practical experience with the use of 3D seismic information from successes and failures in the field.

Experience was especially important to the interpretation of seismic results. It soon became clear to the industry that this was the stage of the information gathering process where proprietary advantage was most important. Anybody could purchase 3D data and process the data using dedicated computer workstations, but interpreting the results for hydrocarbon potential is a combination of art, science, and experience.

Comparing 2D and 3D Seismic Methods

To get a better idea of the difference between 2D and 3D methods, consider the depiction of a cross-section of subsurface layers in Figure 3-1 (end of this chapter). A 2D survey consists of a sound source S and a series of receivers R laid out along a single azimuth at specific distances from the source.[40] The source emits a sound wave that travels through the earth and reflects off the impedance contrast between layer 1 and layer 2.[41] Part of the energy continues on a refracted path through layer 2 and reflects back to the surface at the interface between layers 2 and 3.[42]

Using geometry, computers calculate the V-shaped paths of the reflected signals. Since the locations of the source and receiver are known precisely, one can calculate the depth of the rock layers beneath the midpoint between the source and receiver on the basis of the time required for the sound to travel from the source to the receiver. With many receivers laid out on a line from the sound source, many such midpoints and corresponding depths can be

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40 The acoustic source on land is produced by explosives or, in more sensitive areas, a truck mounted vibrator. Marine sound sources are air guns that displace water volumes.

41 The harder the rock in layer 2, the higher the acoustic impedance, and the more energy that is reflected back to the surface.

42 The wave path bends at each layer interface as described by Snell's Law. Snell's Law was originally applied to light rays and optical reflections, but it applies equally well to seismic waves and the earth.

calculated. The sources and receivers are then moved, along the same azimuth or to a parallel azimuth, to map a larger subsurface area. A 2D survey entails data collection from many parallel lines.

The continuous movement sources and receivers creates overlapping, or redundant, samples of data for the same midpoint location. The collection of all combinations of source-receiver pairs for the same midpoint location creates a sample of observations generated by sound that has traveled a variety of distances. These observations are collected and assembled according to time-of-transit and then converted to depth calculations. The redundancy of midpoint observations raises the noise to signal ratio and improves the resolution of the subsurface image.

The foregoing example assumes that the subsurface rock layers are parallel to the surface. This is not always the case. In fact, such a case is usually uninteresting to petroleum companies looking for oil and natural gas traps. More interesting are structural anomalies such as anticlines and faults that serve to trap hydrocarbons and prevent them from migrating to the surface. These anomalies are harder to map, however. For example, consider Figure 3-2 (end of this chapter), which differs from Figure 3-1 in that the subsurface rock layers are now inclined. As a consequence, the midpoints of the distance between the source S and receiver R are not located directly above the points on the rock layers where the acoustic reflections occur. The midpoints in this instance give a misleading impression of the location of the rock layers. The same problem occurs whenever dips and steep vertical features in rock layers are encountered. The problem is addressed through a process called "migration," which attempts to restore seismic reflections to their true subsurface positions. Seismic migration involves the use of velocity models constructed by geophysicists to estimate and correct for anticipated refraction effects as sound waves pass through rocks of differing sonic velocities.

To obtain a high quality resolution of a specific subsurface area requires seismic shooting over a much wider surface area. This follows because many redundant shots of the same subsurface points are required using source positions at different , and sometimes distant, points on the surface. The area of high quality resolution looks like the small end of a cone that extends from the subsurface location to be mapped up to the wide end at the surface. The wide end of the cone at the surface indicates the area that must be surveyed in order to obtain the high quality resolution below. Although seismic reflections are received outside this cone, the further one moves away from the cone the fewer redundant observations are received for the same subsurface location and the lower the quality of resolution at that location. It is also noted that the deeper one goes in mapping a particular subsurface structure, the larger the area of seismic shooting on the surface required to image that subsurface structure.

The tradeoff between cost and resolution quality is clear.[43] The wider and deeper the subsurface area of interest, the higher the cost of a seismic survey. Moreover, the costs and obstacles are much higher on land than at sea. On land, time and expense are required to obtain landowner's permission to survey across their property and to continuously move

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[43] It is not uncommon to hear seismologists claim that most dry holes are drilled in areas outside the cone of high resolution. This occurs because of a decision to reduce seismic surveying costs by reducing the amount of redundancy or the area covered by the cone of high resolution.

sources and receivers, while acoustic interference from surface activities, particularly near highways and urban areas, reduces the signal to noise ratio. Marine seismic surveying employs specially designed ships that tow a large area of receivers, each of which is precisely located with respect to the acoustic source (air gun) using the global positioning satellite system. There are no landowners to contend with, fewer sources of extraneous sound interference, and a great deal of area can be covered quickly.

In contrast to a 2D seismic survey, which collects data along a given azimuth of the earth's surface to interpret a vertical cross-section of the earth beneath the azimuth, a 3D seismic survey collects data over an area of the earth's surface to interpret a volume of earth beneath that surface area. As illustrated in Figure 3-3 (end of this chapter), the distribution of receivers R are positioned with respect to the sound source S so that each shot from the source will be received along a variety of different azimuths. This variation in azimuths is an important element that accounts for a dramatic improvement in the resolution of 3D surveys relative to 2D.[44] The large number of observations associated with each shot also accounts for the enormous increase in data from 3D surveys relative to 2D surveys.

On land, the geophone receivers may be positioned both horizontally and perpendicularly to the source to maximize the distribution of angles in the shot lines. On water, the hydrophone receivers and the air gun sound source are usually towed by the same ship, thus limiting the distribution of angles.[45] The increase in the number of source-receiver pairs at different positions and angles generates an enormous increase in the amount of data collected with 3D over 2D surveying. As noted above, in the early days of using 3D methods, limited data processing capability was the primary constraint on the adoption of 3D methods.

With 3D data, the migration methods for restoring seismic reflections to their true subsurface positions are more sophisticated than with 2D. In constructing velocity models with 2D data, for example, assumptions must be made about acoustic responses from areas outside the plane of the seismic line. With 3D data, these responses are actually recorded. Another example involves the migration of data that passes through a body of salt. Salt drastically alters the velocity of seismic waves so that simple time migration used with 2D data makes it virtually impossible to image the subsalt structure. In particular, seismic waves pass through salt much faster than adjacent sediments, causing the base of the salt structure and deeper seismic reflections to appear higher than they really are. In addition, the sound waves are refracted in unpredictable ways so that noise rather than signals are recorded. The problem is complicated because salt bodies are typically bounded by faults and other structural complexities.[46]

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[44] Another important variable for resolution is the distance between the receivers.

[45] The importance of the global positioning system for determining the precise location of the receivers relative to the source becomes obvious when it is noted that ten to twelve streamers of hydrophone receivers may be towed for several thousand meters behind the ship. The continuous movement of the ship means that the position of the sources and receivers is continually changing with respect to the surface of the earth. In addition, the action of wind and currents on the streamers will cause the hydrophones to stray from parallel straight lines.

[46] Salt tends to flow like a liquid under subsurface pressures. Thus, a fault or other structural trap is required to keep the salt structure in place.

Migration techniques used with 3D data increase the chance of correctly positioning the location of subsalt structures and of mapping the interfaces between salt and sediment layers. These techniques are called pre-stack and post-stack depth migration methods. Stacking refers to the collection and averaging of common midpoint data. Pre-stack depth migration involves the migration of recorded events from each individual sonic path before the data are summed. Post-stack depth migration attempts to adjust the summed data for changes in velocities to estimate depths below the salt. Experience gained from using these methods has led to selective and usually proprietary methods for fine-tuning the analysis. One indication of the improvements achieved in these methods is the first discovery of a subsalt hydrocarbon deposit by an Exxon-Conoco team in 1990, and the first discovery of a subsalt commercial deposit by a Phillips-Anadarko-Amoco group in 1993, both in the Gulf of Mexico.

Using 3D data, a three-dimensional model of a subsurface area is constructed that may be dissected either horizontally or vertically. A vertical slice gives the same, only better, picture of a cross-section of the subsurface geologic structure as 2D data. Horizontal sections, also called time slices because they represent different time periods in which sediments were deposited, can be literally peeled off a few feet at a time to reveal ancient river channels and sandbars. Such a planar view would be impossible without 3D seismology. This information is valuable in understanding the processes by which sedimentary layers were formed.

The primary objective of most reflection surveys, whether 2D or 3D, is to map the geologic structure created by faults and the interfaces between rock layers of different densities. Structural interpretation, as the process of identifying such prominent features is called, is also the strength of reflection surveys. Another objective is called stratigraphic interpretation, which is the process of determining the density and composition of various rock layers. Structural interpretation is obtained from the travel times of seismic waves, while stratigraphic interpretation is obtained from the amplitudes of those sound waves as they pass through rock layers of different densities.

Structural interpretation is the primary goal of seismology because oil and gas deposits are located in natural traps, or impervious containers, that have prevented the hydrocarbons from migrating to the surface millions of years ago. These traps are usually defined by structural anomalies. Stratigraphic interpretation is valuable in identifying layers of gas relative to oil, water and surrounding sediments, since gas has a large impedance contrast with the others. The difference in amplitudes between a gas-bearing interval and surrounding areas often is the basis for a “bright spot” in a seismic survey; that is, a telltale indicator of a gas reservoir.

Applications of 3D Seismic Information

Ironically, 3D seismic surveying was not used initially to explore for new hydrocarbon reservoirs, but to aid in the development of known reservoirs. The reasons for this are two-fold. First, in the early years the cost of a 3D survey was at least three times that of a 2D survey, so applications of 3D were directed to where it was thought the investment had the greatest payoff. A 3D survey could be restricted to the immediate vicinity of a known reservoir, while 2D is used to survey broad areas to find new reservoirs. 3D immediately proved its worth in development applications because it is capable of revealing minute details about a reservoir that are not possible with other methods.

Second, the benefits to be obtained from the use of 3D seismic as an exploratory tool were not fully appreciated at first. Experience was required to convince management that the added cost of 3D surveys was worth the benefit. Even today, firms often look to cheaper 2D surveys first to determine where to spend their exploration dollars on 3D. However, the cost of 3D surveys has been falling over time with improvements in technology and increased competition among seismic service companies, particularly in marine applications, and the benefits to exploration are becoming better appreciated. As a consequence, 3D seismic is now thought of more as a primary exploratory tool than as a development tool.

Nevertheless, as a development tool, 3D seismic information could pinpoint locations to drill in a reservoir for maximum recovery of oil in place. Sometimes this was because the image revealed the correct boundaries of the reservoir, at other times by distinguishing different oil and gas zones in a reservoir, and still other times by identifying isolated pockets of oil and gas.

The third application of 3D seismic information is in monitoring a producing reservoir over time. Adding the time dimension by acquiring a time-sequence of 3D images, called 4D seismology, enables producers to manage the depletion of an oil reservoir more efficiently than before by monitoring the penetration of water or gas into the reservoir and avoiding "coning" around the wellbore.[47] The same procedure would be followed to monitor the progress of enhanced oil recovery methods such as water flooding, where water is pumped into the reservoir through injection wells in order to force oil through the reservoir and toward producing wells.

To recap, at the exploratory stage, 3D increases the success rate of both exploratory and development wells. A corollary of higher success rates is a reduction in the number of wells that need to be drilled to exploit the same number of prospects. At the same time, 3D surveys reduce the error rate that results from overlooked prospects that are commercially viable and should have been explored. One set of prospects in this category is small oil and gas reservoirs that would not be identified, or would be deemed too small to be worth exploiting, on the basis of 2D information. A second set of prospects includes reservoirs that lie below salt bodies or lava flows, that can not be identified with 2D information. At the development and production stages, 3D information is used to formulate optimal development and production strategies that aim to maximize the flow of earnings over time from a reservoir with a minimal investment in production facilities. Compared to earlier practices, this often means both increasing the rate of production and the total volume that can be extracted from a reservoir. Because 3D seismology provides benefits at three stages in the production process, it is difficult to accurately assess the full benefits of this technology.

[47] Coning refers to the penetration of water or gas to the wellbore of an oil well, causing the well to produce water or gas rather than oil. Gas production may be unwanted because it is the source of natural pressure for extracting oil, or because the well is located too far from a gas pipeline system to make possible to market the gas. When a well cones water, it must be shutdown and redrilled.

Only partial information is available of the amount of 2D and 3D seismic surveying that is conducted in the U.S.[48] The best indication of the growing popularity of 3D methods is provided by the number of seismic permits issued by the Minerals Management Service for the Gulf of Mexico (see Figure 3-4, end of this chapter). While the total number of seismic permits has declined over the past several years, the number of 3D permits has grown from less than 5 percent in the early 1980s to 40 percent or more of the total. Still, the number of 2D permits continues to exceed the number of 3D permits.

IMPLICATIONS FOR PRODUCTIVITY

There are no comprehensive data available that may be used to calculate the precise productivity implications of 3D seismology. What is available are the anecdotal experiences of individual companies that have compiled and published records of their drilling activities, including most importantly their comparative experiences with the use of 2D and 3D seismic techniques. Combining these experiences provides a good picture of some of the benefits of using 3D seismology.[49] Nevertheless, as indicated above, the full benefits will not be completely captured by the successes and failures in finding and developing reserves. In addition to the benefits from improved production strategies, 3D information also makes it possible to implement the drilling and deepwater technologies described in the next two chapters.

Improvement in Drilling Success Rates

Table 3-1 summarizes the experiences of five companies regarding the comparative success rates using 2D and 3D seismology for exploration and development drilling in different locations and widely different circumstances. Because of the differences, the numbers cannot be simply averaged to get an estimate of the benefits of 3D. Rather, as discussed below, some of the numbers should be given greater weight than others. Adjusting for the weights, it is concluded that 3D is responsible for increasing the exploratory success rate from about 20 percent to about 50 percent, and the development success rate from about 70 percent to about 85 percent. The increase in exploration success due to 3D methods (250 percent) is truly dramatic. The fact that the development success rate does not rise as dramatically as the exploratory success rate is not surprising in view of the already high success rate, nor is the benefit of 3D at this stage reflected fully in the success rate. When 3D is used for development purposes it also contributes to higher recovery rates and extraction rates as well.

To explain how the above conclusions were reached, it is necessary to describe the experiences underlying the figures in Table 3-1 in more detail, starting with Amoco. Amoco

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[48] Data have been recorded until recent years on the number of seismic crew months at work and on the surface distances covered by 2D and 3D surveys. However, the number of crew months is an inaccurate measure of the amount of surveying undertaken because of improvements in measuring techniques. Also, the areal coverages of 2D and 3D are hard to compare because the first is recorded in linear distances and the second in square miles covered. Data are also available on expenditures for acquiring 2D and 3D data, but these data suffer from the same shortcomings as above.

[49] After all, as someone once said, “the plural of anecdote is data.”

created a “3D Seismic Network of Excellence” group to, among other things, assess the value of using 3D seismic methods within the company. Reports published as a result of this effort represent the most accurate, comprehensive, and detailed look at the advantages of using 3D, and therefore are given the most weight in Table 3-1.[50] The results are based on data collected for 159 3D surveys conducted during 1991-1994 in several areas of the world.

Table 3-1. Drilling Success Rates: With and Without 3D Seismic

Company and Location	Exploration Drilling	Development Drilling
Amoco: Worldwide		
With 3D	.48	.86
Without 3D	.13	.57
Exxon: Gulf of Mexico		
With 3D	.70	
Without 3D	.43	
Exxon: U. K. No. Sea		
With 3D	.47	
Without 3D	.36	
Exxon: Netherlands Offshore		
With 3D	.70	
Without 3D	.47	
Fairfield Industries: Gulf of Mexico		
With 3D	.50	
Without 3D	na	
Fairfield Industries: Louisiana Shallow Water		
With 3D	.57	
Without 3D	.20	
Fairfield Industries: Louisiana Onshore		
With 3D	.43	
Without 3D	.20	
Texaco: Louisiana Settlement		
With 3D	.62	.95
Without 3D	.33	.75
Mobil: South Texas		
With 3D		.84
Without 3D		.70

[50] Three papers present the analysis by William K. Aylor: “Business Performance and the Value of Exploitation 3D Seismic," *Geophysics: The Leading Edge* (July 1995), p. 797; “Business Impact and the Value of Exploration 3D Seismic,” Amoco Corporation (September 15, 1995); and “The Business Impact and Value of 3D Seismic, presented at the Offshore Technology Conference held in Houston, Texas (May 1996).

The surveys are divided into two groups, labeled exploration and exploitation, where the former refers to wildcat exploration and the second includes new field rate acceleration and older field extension. The numbers that appear under the label "development" in Table 3-1 come from the exploitation group. The results are based on 998 production wells that were drilled with and without the benefit of 3D.[51] The experience with exploration wells refers to a total of 272 wells, of which 38 were based on 3D information and 234 were not. These numbers reflect the fact that "Amoco in the past has used 3D quite late in field development."[52] Like many companies, Amoco at first used 3D primarily as a development tool and only recently has come to use it as an exploratory tool.

The value of 3D as an exploratory tool comes not only from drilling fewer dry holes than with 2D, but also from finding resources that 2D would have ignored. An example is cited by Aylor for an exploratory block in the North Sea. With 2D methods, eight prospects were found with estimated probabilities of success between 22-53 percent, while 3D information placed the probability of success below 10 percent for six prospects (thus, effectively condemning them) and above 60 percent for two prospects (thus, making them likely targets).[53]

Exxon's experience refers to the "geologic" success rate associated with drilling 244 exploration wells in three offshore areas, where geologic success means that hydrocarbons were discovered, even though they may not be economic to develop.[54] Geologic success therefore overstates the meaning of success used here and Exxon's numbers in Table 3-1 should be deflated in comparison with the others. Also misleading is the observation that success rates for wells based on 3D data are about 50 percent higher than those based on 2D data. The difference in success rates should be even greater because 3D is more accurate in discerning the presence of commercially valuable deposits than 2D. This is one of the important findings by Aylor, as indicated by the use of 3D to reevaluate 2D prospects.

The Fairfield Industries entries refer to three different samples of observations obtained in 1994.[55] The first entry is obtained from a survey of 23 companies actively exploring in the Gulf of Mexico (out of a total of 71 operators in 1994). Thirteen of the companies (57 percent) responded that they do not use 3D for exploration, a response rate that is consistent with recent data in Figure 3-4 (end of this chapter). The remaining ten companies (43 percent) said they drilled 104 wildcat wells in the Gulf during 1993 and 1994

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[51] Aylor's "Value of Exploitation" paper lists 115 3D surveys, including "48 that were exploitation, 44 exploration, 23, both, 38 land, 75 marine, and 2 both." (*Op. cit*., p. 797.) The "Value of Exploration" paper lists 158 3D surveys, but discusses only exploration wells drilled with and without 3D.

[52] Aylor, "The Business Impact and Value of 3"D Seismic," p. 77.

[53] *Ibid.*, p. 76.

[54] M. Schoenberger, "The Growing Importance of 3D Seismic Technology," presented at the Offshore Technology Conference held in Houston, Texas (May 1996).

[55] Marc A Lawrence, Hugh T. Logue, and Don A. Grimm, "Reducing Dry Hole Risk with 3D Seismic Data," Fairfield Industries, Houston, Texas (undated, 1995). Fairfield Industries is an independent seismic service company.

using 3D data, and that 53 were successful (51 percent success rate). No information is presented on success rates with the use of 2D data.

The second Fairfield entry reflects the company's experience with regard to exploration projects in shallow water Offshore Louisiana. No information is provided regarding the extent or nature of this experience, though one of the authors indicated that the numbers have not been contradicted when presented before audiences of exploration personnel.[56] The same comments apply to the third entry regarding exploration onshore in South Louisiana.

The Texaco entry refers to experience resulting from implementation of the Global Settlement Agreement, which was the settlement of a dispute between Texaco and the state of Louisiana over natural gas royalty pricing. In addition to a $250 million payment to the state, Texaco agreed to spend $152.25 million over a five year period starting in 1994 to drill on state leases in South Louisiana. Information regarding these drilling activities is provided to the Louisiana Department of Natural Resources and is monitored by the Center for Energy Studies at Louisiana State University.[57] During 1995, Texaco drilled 14 wildcat wells, of which 8 were drilled with 3D information and 6 were not; and 34 development wells, of which 22 were drilled with 3D information and 12 were not.[58] The resulting success rates are quite high in comparison with the others, which is a reflection of the maturity and low risk nature of the South Louisiana province.

The Mobil entry refers to relatively low risk development drilling in the South Texas Lower Wilcox trend, which provides "a unique opportunity to compare results from like vintages of 3D and 2D seismic data."[59] Sixty-nine wells were drilled during 1991-2, of which 32 were based on 2D data and 37 were based on 3D data. Although the historic success rate for development drilling in this area was 72 percent prior to 1991 based on 2D data, 2D was regarded as inaccurate in imaging the complex subsurface structure. Mobil and its partners, Amoco and Conoco, decided to purchase 3D data for a total cost of $1.9 million, including acquisition and processing. However, an eight month delay in the receipt of 3D data prompted the partners to start drilling early based on 2D data, purchased for $1.1 million and covering an area roughly equivalent to that surveyed with 3D methods.

The average cost of drilling and completing a well was $800,000, while the average cost of a dry hole was $500,000.[60] In addition to dry hole savings, the increased accuracy of 3D led to drilling in better locations. The average 3D well brought in 14 percent more

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[56] Conversation with Marc Lawrence, Vice President of Fairfield Industries, in Houston, Texas, August 1996.

[57] The author thanks Allan Pulsipher, Director of the Center for Energy Studies, for providing information from the 1995 report on the Global Settlement Agreement.

[58] Of the 8 wildcat wells using 3D, 5 were successful, and 3 contained oil while 2 contained gas. For comparison with the 6 wildcats drilled without 3D, 2 were successful and both were gas. The successful development wells were predominately oil wells: 15 out of 21 with 3D, and 7 out of 9 without 3D.

[59] Patricia B. Jeffers, Thomas A. Juranek, and Michael R. Poffenberger, "3D versus 2D Drilling Results: Is There Still a Question," *Proceedings: 63rd Annual Meeting of the Society of Petroleum Geologists,* Washington, D.C, (1993), p. 435.

[60] The difference in the two costs is the cost of completing a well. Completing a well involves the installation of casing and wellhead equipment.

reserves than the average 2D well, not counting dry holes, or 37 percent more reserves including dry holes. After deducting seismic and drilling costs, the net present value of the stream of earnings from 3D wells was double that of the 2D wells. These results demonstrate the value of 3D over 2D even in low risk development applications.

The trade press is replete with other examples of the cost-effectiveness of 3D surveys over 2D, many of which describe how 3D saved money by avoiding unnecessary drilling. For example, in 1992, Mitchell Energy decided to supplement its 2D survey of the Palacios Field on the Texas Gulf Coast with 3D information.[61] Although oil and gas development in this field has taken place since 1937, 3D data revealed a much different fault pattern than that thought to exist on the basis of 2D data and earlier experience. The new information enabled geologists to reconstruct the geologic history of the entire area and, as a consequence, enabled the operator to avoid drilling more unsuccessful wells. Because of the structural characteristics of the newly discovered fault pattern, it was realized that much of the area under consideration is subject to drainage and pressure depletion from wells already drilled. Thus, the plan to drill more development wells was scrapped, at a savings of three times the cost of the 3D survey.

In another demonstration of the value of 3D seismic data, Gulf Oil Corporation obtained its first operational 3D survey of the Eugene Island field in 1979 after development had already begun.[62] The results of the survey showed that two platforms already in place were in fact developing the same reservoir and that a third platform would have to be added to drain the field effectively. The survey led to the drilling of 20 successful wells without a dry hole, thus saving the company about $4 million for each dry hole avoided.

Two final examples focus directly on the productivity enhancement of 3D seismic information: obtaining more output with less inputs. One example is the prospective development of the Seeligson field in South Texas, where routine development based on 2D information would involve 31 wells at a cost of $18.6 million, “an expensive and probably uneconomic project."[63] Based on a 3D geologic model, optimal development could be accomplished with only eight wells at a cost of $5.4 million. Moreover, the new strategy will recover 10 percent more of the hydrocarbons in place at one-fourth the average cost of the older strategy. The second example involves the development of a gas field offshore of Venezuela, where 3D information reduced the number of development wells from 120 to 35 and the amount of recoverable gas increased by 36 percent.[64] In this case, unit costs declined to one-fifth of that of the older technology.

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61 Ron McWhorter and Bill Torguson, “Palacios Field: A 3D Case History,” *Geophysics: The Leading Edge* (December 1995), pp. 1225-1230.

62 P. S. Horvath, “The Effectiveness of Three-Dimensional Seismic Surveys: Case Histories,” *Geophysics*, vol. 50, no. 12 (December 1985), pp. 2411-2430.

63 William L. Fisher, “Technology and the Modern Oil and Gas Industry,” paper presented at the Aspen Institute, Aspen, Colorado, June 30, 1996, p. 5.

64 *Ibid.*

The Reduction in Exploration and Development Costs

The cost of exploring for oil and gas includes, among other things, the cost of seismic surveying, geophysical modeling, and exploratory drilling. 3D seismology affects overall exploration costs by increasing surveying costs and reducing drilling costs. Based on the citations in the preceding section, surveying costs for 3D are roughly double those of 2D for the same amount of coverage, including the costs of acquisition, processing, and interpretation.[65] Exploratory drilling costs are reduced by 3D as a result of the increase in the success rate from 20 percent to 50 percent per well drilled (see the discussion of Table 3-1). Thus, a doubling of seismic costs leads to a 2.5-fold increase in the discovery rate.[66]

The foregoing information can be used to calculate an estimate of the impact of 3D seismology on average finding costs. Average finding costs (AFC) may be decomposed into the sum of average drilling costs (ADC) and average non-drilling costs (ANC), all expressed per unit of discoveries:

$$\text{AFC} = \text{ADC} + \text{ANC}$$

AFC is changed as a result of the introduction of 3D by an increase in the discovery rate by a factor of 2.5 and by an increase in the cost of seismic services by a factor of 2. The new AFC, written as AFC*, thus becomes:

$$\text{AFC}^* = (1/2.5)[\text{ADC} + (2t)\text{ANC} + (1-t)\text{ANC}]$$

where t is the share of seismic surveying costs in ANC. The change in average finding costs is thus:

$$\text{AFC} - \text{AFC}^* = (1/2.5)[1.5\text{ADC} + (1.5 - t)\text{ANC}]$$

Dividing through by AFC gives the percentage change in average finding costs due to 3D seismology.

As Table 3-2 shows, in recent years drilling costs are about 50 percent of total exploration costs, while seismic costs are about 40 percent of non-drilling costs. Inserting these numbers into the above equation gives:

$$\text{Percentage change in AFC} = (0.6)(0.5) + (0.6 - 0.4)(0.5) = 0.40$$

Thus, 3D seismology may be said to reduce average finding costs by 40 percent.

The same approach may be used to calculate the reduction in the average cost of development drilling made possible by 3D-related increases in success rates. However, the formula may be simplified for two reasons. First, it may be assumed that there are no additional seismic costs resulting from the use of 3D and, second, that there is no need to distinguish between drilling and non-drilling costs. The first simplification implies that 3D surveying for exploratory purposes is adequate for development purposes as well, so that the

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65 The cost premium of 3D relative to 2D has declined in recent years. In a survey of the industry in 1992, it was concluded that 3D was three-times as costly as 2D. See Vicki L. Bruch and Douglas R. Bohi, "The Impact of 3D Seismic Technology on the Petroleum Market," Sandia National Laboratories, April 1993, p. 5.

66 The reduction in drilling costs results from fewer dry holes. The probability of a dry hole falls from 0.8 to 0.5.

use of 3D for development involves zero marginal cost.[67] The second simplification follows because a reduction in the number of wells that comes with an improvement in the development success saves both drilling and non-drilling expenses associated with the foregone wells.[68] That is, the improvement in the development success rate from 70 percent without 3D to 90 percent with 3D (based on the numbers in Table 3-2) can be applied to all development costs. Thus, the 1.29-fold improvement in the success rate may be said to reduce average development costs by 22 percent (equal to 0.29/1.29 x 100).

Table 3-2. Components of Exploration and Development Expenditures

Year	Exploration Expenditures			Development Expenditures	
	Drilling	Seismic	Other	Drilling	Other
1977	3,044	1,412	1,417	6,120	7,077
1978	3,888	1,539	1,244	6,765	7,605
1979	5,114	1,842	1,465	7,519	8,436
1980	7,987	2,500	1,903	9,004	19,151
1981	10,197	3,185	2,535	12,427	37,053
1982	9,437	2,960	2,950	13,950	26,301
1983	5,964	2,614	2,843	7,752	26,097
1984	6,828	2,362	3,031	8,633	23,787
1985	6,054	2,058	2,867	8,855	21,334
1986	2,501	1,093	2,031	4,733	15,062
1987	1,883	999	1,728	3,786	14,758
1988	2,653	1,107	1,684	4,400	14,166
1989	2,091	827	1,365	4,281	13,990
1990	2,402	841	1,275	4,911	13,393
1991	2,057	666	1,080	4,368	13,076
1992	1,185	475	758	3,487	11,066
1993	1,335	399	635	3,910	9,426
1994	1,797	386	589	4,309	7,907

Note: data are from 36 Major Petroleum Companies
Source: Energy Information Administration, Financial Reporting System.

[67] This assumption is not strictly true, but we have little choice in the matter because available data lumps all seismic costs under exploration costs. There is no way to break out additional seismic work for development purposes alone.

[68] While there is no need to distinguish between drilling and non-drilling expenses, there is a reason to distinguish among drilling expenses because the operator will not undertake the cost of completing a dry hole. Since completion costs are part of drilling expenses, avoiding a dry hole will not save this part of drilling costs. Unfortunately, the data do not make a distinction between completion costs and other drilling expenses.

The foregoing calculation understates the full reduction in development drilling costs, as examples described in the previous section illustrate. For example, in circumstances where 3D led to a reduction in the number of development wells required for optimal development, but no change in the success rate, there is a corresponding increase in productivity in the wells that were drilled and a reduction in overall development costs. The avoided development wells would have been successful in a commercial sense, but they were unnecessary to the efficient development of the reservoir. Eliminating the superfluous wells would lower development costs without a change in the success rate.

IMPLICATIONS FOR RESOURCE DEVELOPMENT

The amount of hydrocarbons physically located in the earth's crust *per se* is largely irrelevant to the well-being of society. What is important is the amount of hydrocarbons that can be found and recovered at current and future costs of production. As long as expected net revenues exceed expected costs, whatever their magnitude may be, exploration and development activity will continue. If expected costs exceed expected revenues, exploration and development will cease no matter how much oil and gas remains in the earth's surface.

In the absence of technological improvements, expected costs will rise over time as a result of diminishing returns in reserve replacement. Deposits that are the largest and easiest to find will enter the reserve inventory first. Once found, other things being equal, those prospects with lowest development and production costs will tend to be exploited first. Of course, surprises can and do occur because knowledge of the resource base is imperfect, but depletion of the resource base will inexorably push up costs of production unless the means of finding and producing the resource improves.

Offsetting the Depletion Effect

The depletion effect may be represented by an exponentially declining path of reserve additions over time, for any given level of exploration and development investment. The effect of technology improvement is to shift out the decline curve, and delay the time that diminishing returns will set in or at least slow its progress. This is the role of 3D seismic methods. We have seen from the examples above that 3D seismology effectively reduces the cost of finding and recovering hydrocarbons in two basic ways: by finding resources that would have been ignored otherwise, in both new and old fields, and by increasing recovery rates from known reservoirs.

Perhaps the most exciting frontier application of 3D methods is in finding oil and gas deposits below salt formations in the Gulf of Mexico. Not long ago this part of the subsurface area was considered to be unexplorable because the inaccuracy of 2D images of formations below thick layers of salt. With 2D information it is impossible to predict the location of hydrocarbon deposits. Using 3D methods, Phillips Petroleum company (and partners Anadarko and Amoco) discovered the first commercial subsalt deposit in 1993 in the Mahogany field, located in 370 feet of water with a well drilled to 16,500 feet below the sea floor. Phillips and Anadarko followed with a second commercial discovery in the Teak field in 1994, and with the third discovery in the Agate prospect (located 6 miles from Mahogany) in 1996. These discoveries are particularly exciting because 60 percent of the Gulf of Mexico is covered by salt layers, some more than 3,000 feet thick. Together with other parts of the U.S. and world characterized by thick layers of salt, a whole new dimension to oil and gas exploration could be on the horizon.

While 3D has contributed to a major breakthrough in subsalt exploration, the activity is still regarded as high-risk and expensive.[69] Part of the expense follows from the additional time required to drill a subsalt well, because an extra string of casing must be cemented into the borehole at the salt interval to prevent salt creep. But the main risk follows from low success rates. As of January 1996, 33 subsalt wells have been drilled with only 5 discoveries, indicating the continuing difficulty of predicting subsalt oil and gas deposits.[70] The mathematical and interpretation tools needed to create and accurately position images of features below salt are in the early phase of development. Much more needs to be learned about subsalt seismic techniques and geology to lower the risks, and learning can be achieved only through additional experience. Each additional subsalt seismic survey and exploratory well, whether successful or not, will improve the skill level for approaching the next prospect. Some tenacious operator may eventually put together the seemingly extraneous bits and pieces of information that will lead to the development of accurate indicators of hydrocarbon potential.

Prospects for the Future

Three-dimensional seismology may delay the depletion effect on exploration and development productivity, but will not eliminate it. Eventually, the cost of adding new reserves must rise as the resource potential susceptible to discovery by 3D methods is depleted. This is the pattern of earlier exploration technologies, where each innovation provided a unique advantage in locating reservoirs compared to older methods, and resulted in a surge in the discovery of reservoirs of a particular variety or in particular locations.[71] For example, prior to the use of geophysical exploration methods, oil was found by identifying surface structures that revealed the possibility of anticline traps. Once all such surface structures were drilled, discoveries fell off until the next technology came along. The introduction of the reflection seismograph in the 1930s led to another surge of discoveries by exploiting new information about subsurface geology. By the 1950s, discoveries found by this technique faded, until it was replaced by analog reproducible recording, and later by digital recording and processing.

Like 3D methods, each past technology improved the industry's capability of finding new deposits in particular circumstances. Once those opportunities are depleted over time, the rate of new discoveries will fall until the technology is replaced and a new set of opportunities is revealed. 3D methods, like earlier versions of reflection seismology, are

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[69] "The Subsalt Technology Play," *Oil and Gas Journal*, (march 18, 1996), p. 25. To spread the risk, multiple partnerships are commonly formed to explore subsalt prospects.

[70] Leonard Le Blanc, "Inching Closer to Predicting Subsalt Oil and Gas Prospectivity," *Offshore,* (January 1996), p. 44.

[71] See Roy O. Linseth, "The Next Wave of Exploration," *Geophysics: The Leading Edge of Exploration* (December 1990), pp. 9-15.

particularly useful for identifying structural traps.[72] In time, most structural traps will have been identified the advantages of using 3D seismology may be expected to fade. Even most subsalt structures will eventually be explored with improved 3D methods.

However, 3D seismology is less effective in locating stratigraphic traps.[73] Many stratigraphic fields have been found around the world, though they are usually discovered by accident, while drilling into structural formations, or by methods other than seismology.[74] As one expert put it, "Stratigraphic traps are a much more slippery objective for the geophysicist. They rarely have any vertical extension...and are not well defined by conventional seismic sections. And while structural folds usually deform many strata in unison, confirming their presence by considerable vertical expression on the seismic cross section, the stratigraphic reservoir is usually very specific to a single horizon, and because its extension on the seismic section is lateral rather than vertical the expression is small, local, and very difficult to define."[75] Structural traps tend to be stacked vertically, so the search for similar traps proceeds by drilling deeper. In contrast, the search for stratigraphic traps must proceed laterally by following a specific topography such as an ancient river bed.

The dependence of future productivity gains on success in finding stratigraphic traps is not a new story. Many geologists and geophysicists have entered the profession with the view that the future of the industry lie in the ability to identify stratigraphic traps.[76] That view was held before the advent of 3D seismology and, while it may eventually come to pass, is likely to be preceded by yet another series of technological developments.

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72 A structural trap is a petroleum trap formed by the deformation of the reservoir rock such as a fold or a fault.

73 A stratigraphic trap is a petroleum trap formed by the deposition or erosion of the reservoir rock.

74 *Ibid.*, p. 11.

75 *Ibid.*

76 This is a common response obtained from interviews with geologists and geophysicists about the future of their profession.

Figure 3-1
Simplified Representation of Seismic Reflections

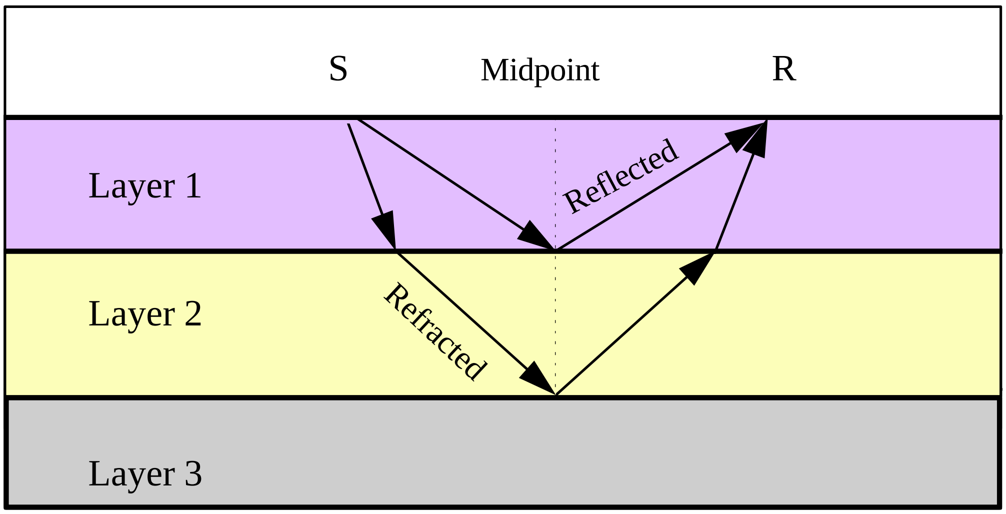


Figure 3-2
Seismic Reflections from Inclined Rock Layers

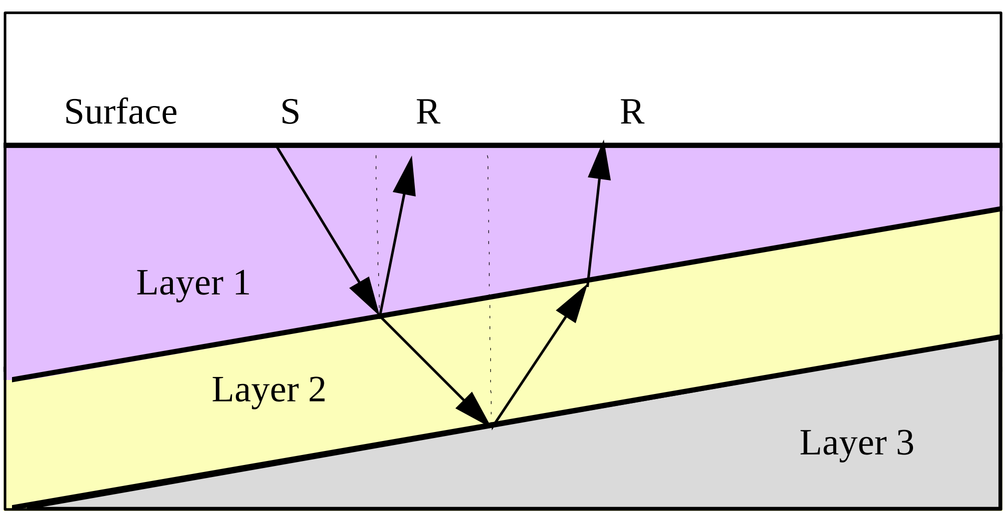
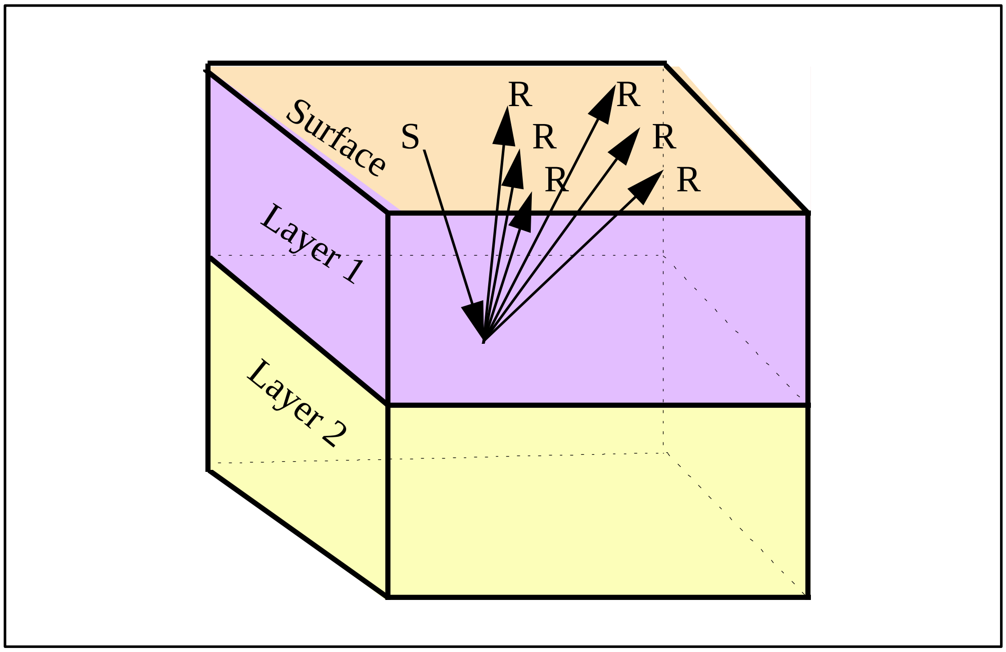
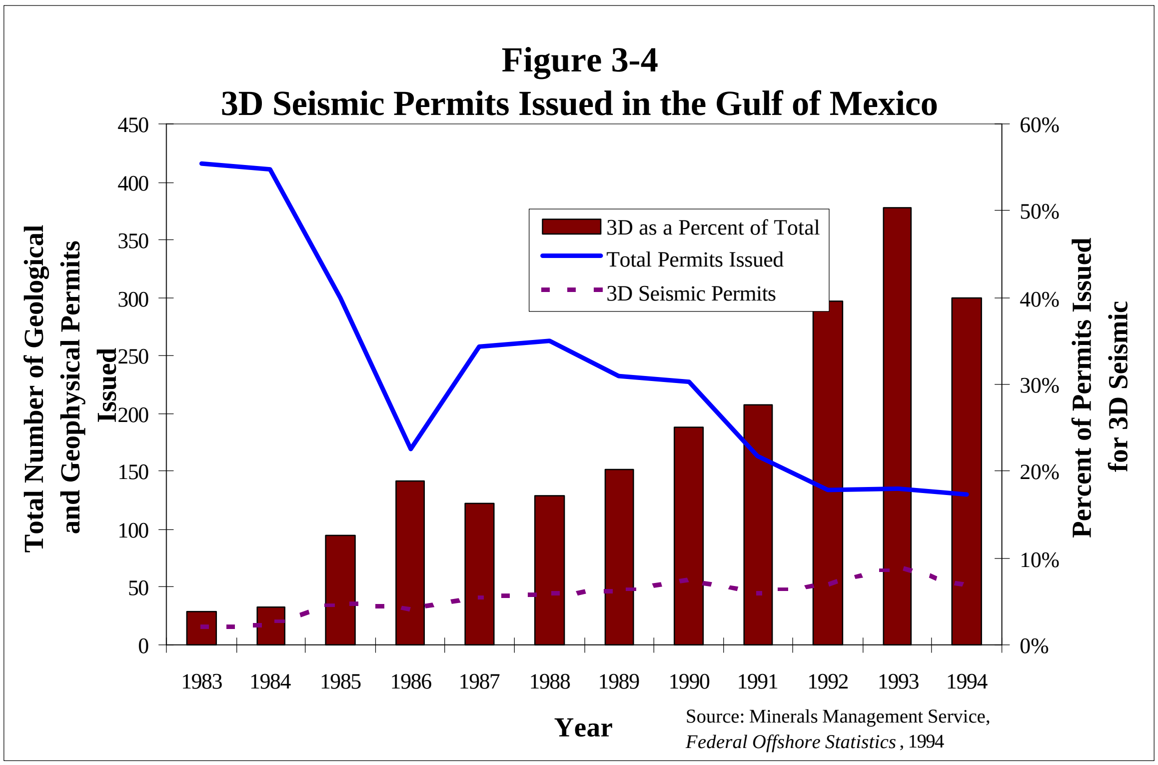


Figure 3-3
Simplfied View of a 3-D Seismic Survey





Chapter 4

HORIZONTAL DRILLING: PRODUCTIVITY AND RESOURCE IMPLICATIONS

The second important innovation of the last decade is horizontal drilling. We begin with a description of horizontal drilling techniques and of the principal applications of this technology. Next comes a discussion of the implications of the technology for industry productivity and, in the final section, for resource development.

HORIZONTAL DRILLING TECHNOLOGY

Oil and gas wells can no longer be thought of simply as vertical shafts created by rotating a pipe connected to a drillbit that grinds its way through rock. Drillers are capable of guiding a drillstring, with a motor at the business end turning the drillbit, that can deviate at all angles from vertical, including at a ninety degree angle, so that the wellbore intersects the reservoir from the side rather than from above. Such techniques are known as horizontal drilling. A comparison of vertical and horizontal wells is pictured in Illustration 4-1 (end of this chapter). Wellbore “A” is a typical vertical well shown penetrating several strata and a single fracture. Wellbore “B” is drilled horizontally into a pay-zone. Note the greater exposure of the wellbore to the pay-zone compared to the vertical well. Horizontal well “C” is shown penetrating several fractures with the same borehole.

The potential advantages of horizontal wells have been appreciated for many years, but commercial success had to await the development of several complementary innovations. Unsuccessful experiments with horizontal drilling were conducted in Texas in 1929, in Pennsylvania in 1944, and in several countries in the 1950s.[77] By the late 1980s, after advances in the development of downhole drilling motors, downhole sensors, telemetry equipment, and 3D seismology, horizontal drilling has become the accepted practice in certain applications.

Advances in Drilling Technology

Horizontal wells begin initially as a standard vertical well, usually drilled using traditional rotary techniques. The start of drilling a well is called “spudding,” which begins with drilling a large diameter “conductor” hole up to 100 feet in depth for insertion of a large diameter steel pipe (e.g., 20-inches) called a “conductor casing.” The conductor casing stabilizes the top of the well and is used to attach a blow-out preventer in case subsequent drilling encounters high pressure gas. A drilling rig is then installed that consists of, among others things, a derrick for hoisting and connecting lengths of steel pipe and a rotary system for turning the drillstring. The drillstring in turn consists of the drill pipe, drill bit, and related downhole equipment. The weight of the drillstring is let down on the bit until between 3,000

[77] Robert F. King, “Drilling Sideways: A Review of Horizontal Well Technology and its Domestic Application,” Energy Information Administration, DOE/EIA/TR--0565, April 1993, p. 7.

to 10,000 pounds per square inch is applied to the bit. When the drillstring is then rotated at 50 to 100 revolutions per minute, the drill bit grinds and crushes rock.

In most vertical wells and some horizontal wells, the rock chips (called "cuttings") are removed from the bottom of the well by injecting drilling "mud" that flows under pressure through the hollow drillstring and out of holes in the drill bit. The drilling mud picks the rock chips off the bottom of the well and forces them to flow upward to the surface in the space between the rotating drillstring and the well wall. At the surface the cuttings are separated from the mud so that the mud can be re-circulated down the well.

The drilling mud performs other critical functions that weigh heavily in decisions to drill a horizontal well. First, the circulating mud cools and lubricates the drill bit. Second, the mud is used to control downhole pressures and prevent blowouts. When the wellbore encounters a formation containing water, oil, or gas, pressure operating on the gas and fluids in the pores of the rock will try to force them into the well. The weight of the mud between the drillstring and the well wall is intended to prevent the gas or fluid from traveling up the wellbore. When the mud fails to contain the gas and fluid, it flows uncontrolled to the surface, and a blowout results. Always dangerous, a blowout is especially serious if a fire is ignited. Blowout preventers located at the top of the well are designed to close the well when a sudden increase in pressure occurs, reducing the risk that a serious accident will occur.

Downhole pressure is monitored continuously to adjust the weight of the drilling mud in order to exert greater pressure on the bottom of the well than is presented by the gas and fluids in the surrounding rock.[78] This is called "overbalanced" drilling. In this case, some of the drilling mud is forced into the surrounding rock and forms a hard mud cake on the sides of the wellbore. While the mud cake stabilizes the sides of the well and prevents gas, oil, and water from flowing into the well, it can create production problems if the pay-zone becomes seriously plugged. Before production can proceed the mud cake must be removed to expose the reservoir formation to the wellbore. Cleaning may be accomplished by mechanical scraping, acid treatment, or the use of explosives. Heavier, oil-based muds are more difficult to remove and more expensive to use than water-based muds, but they are more effective in balancing downhole pressures. Thus, the decision concerning the composition of the drilling mud to be used is important to cost and productivity, and is dependent on the nature of the rock containing the reservoir.

Finally, of direct importance to horizontal drilling, drilling mud is used to power downhole motors. Mud that is pumped down the drillstring enters into the downhole motor, where it drives a turbine that turns the drill bit. After exiting the drill bit, the mud carries away the rock cuttings and stabilizes pressures in the wellbore, as described above.

If the well is to be drilled out at an angle, the downhole motor is lowered into the well and oriented in the desired direction. The mud motor is activated and pulls the drillstring along with it.[79] Cheaper, non-steerable motors require the use of mechanical downhole

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[78] This is called "overbalanced" drilling. There are occasions when "underbalanced" drilling is desired, so that fluids actually flow up the wellbore while drilling is underway. The risk of a blowout is greater with underbalanced drilling, so the procedure must be warranted to undertake the added risk.

[79] A deviated well can be drilled with a surface rotary drill as well. In this case, a steel wedge called a "whipstock" is run into the well on a drillstring and positioned at the desired location using survey instruments.

assemblies that force the motor to move in the desired direction. Steerable downhole motors have articulated pipe-motor assemblies that can be adjusted by remote control. These more sophisticated motors are usually accompanied by a variety of downhole sensors located behind the drill motor, called the "measurement-while-drilling" package. Included in the package are sensors that measure bottom hole temperature and pressure, bit rotation speed and torque, and physical characteristics of the surrounding rock such as fluid content and radioactivity. Radiation readings are used to determine the location of the drill bit in the rock layers.[80] Fluid content is determined by the resistivity of rocks and their accompanying fluids, as measured by an electrical current that is passed through the rock in contact with the wellbore. The information can be transmitted to the surface by "fluid pulse telemetry" in which the data are recorded in pressure pulses that are transmitted up the wellbore through the drilling mud.

If the well proves to be successful, and is to be used for production, it is "completed" by installing casing pipe and wellhead equipment. Casing pipe is thin-walled steel pipe that acts as a stabilizing liner for the wellbore. It is lowered into the hole and cemented into place. Cementing stabilizes the casing string and prevents water from flowing from adjacent formations toward the pay-zone. The type of wellhead equipment used depends on the presence of sufficient pressure in the reservoir to force oil and gas to the surface. All gas wells, but only 5 percent of the oil wells in the U.S., have enough natural pressure to flow to the surface. When pressure is sufficient, the wellhead equipment includes a series of valves and fittings called a "Christmas tree" to control the flow. If the oil well does not have enough pressure to flow to the surface, the Christmas tree is removed and a pump is installed.

One technology not mentioned so far--on-site computer capability--is sometimes said to be the most important innovation in reducing drilling problems with horizontal wells. Computers allow for more detailed planning concerning drilling mud, casing pipe, drilling assembly, and dangerous formations in the area. After drilling begins, computers allow for effective real time monitoring of the drilling progress and a comparison with the drilling plan. Taking the information obtained from the "measurement-while-drilling" package, the computer can match lithological profiles against known or nearby wells to anticipate and avoid costly problems. This information is also used to steer the drill bit through prospective formations, and to identify oil and gas bearing zones when they are encountered.

Applications of Horizontal Drilling

Horizontal wells are most advantageous when reservoir conditions call for greater contact between the wellbore and the reservoir formation. One such example is a reservoir that contains a thin pay zone. The reservoir may appear in cross-section as a narrow band that extends horizontally for a long distance. A vertical well drilled into such a reservoir would encounter a small pay zone and attain a limited capability to draw off oil and gas. In addition to low productivity, a vertical well drilled into a thin pay zone has a high risk of coning,

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The whipstock is designed to bend the drillstring in the desired direction. Steel pipe is sufficiently flexible that it can bend up to a point without significant risk of structural failure.

[80] Of the three common sedimentary rocks--shale, sandstone, and limestone--only shale is radioactive. The other two are potential reservoir rocks, however.

where water penetrates the reservoir and moves toward the wellbore. When the well starts producing water instead of oil, it must be shut down and a new well must be drilled on a different location in the reservoir. Finally, unless many wells are drilled into a thin reservoir, much of the oil-in-place would not be extracted. Productivity can be improved, fewer wells need be drilled, and more oil can be extracted if the wellbore is guided so that it that enters the pay zone horizontally. Drilled this way, a maximum amount of the wellbore is exposed to the formation.

A similar advantage occurs with reservoirs in low permeability rocks. Low permeability means that it is difficult for gas or oil to flow through the interconnections between the pore spaces and fractures of the rock and into the well. Horizontal wells can be economic in low permeability zones when vertical wells are not, because of the difference in contact area between the wellbore and the reservoir. This is also true in heavy oil reservoirs, where steam injection is used to drive oil to a wellbore. Horizontal wells serve as high volume collection points in these applications.

Vertically fractured formations represent another situation where horizontal wells are especially productive. In fact, this application in the 1980s represents the first extensive use of horizontal drilling in the U.S.; specifically, in the Austin Chalk formation located in South Texas.[81] The formation is an oil and gas bearing limestone that extends for many miles. Vertical fractures in the limestone allowed oil and gas to migrate from below the formation up into limestone. Each fracture contains only a modest amount of hydrocarbons and only one fracture at a time can be accessed with conventional vertical wells. A horizontal well, in contrast, can be drilled at an approximate right angle to intersect several vertical fractures, thus multiplying the number of productive zones that can be accessed with the same well.

A final category for which horizontal drilling is well-suited involves re-entry into depleted and abandoned reservoirs. On average, less than 30 percent of the oil contained in a reservoir has been extracted in the past, because it was uneconomic to produce the remaining reservoirs with conventional vertical wells. With horizontal wells, oil-bearing zones that are too thin, less permeable, or too small to be drilled vertically can become economic again. Moreover, re-entry wells are significantly less expensive than new wells, because they use an existing platform or wellbore, and they benefit from prior knowledge about geologic formations that reduces the risk of a poorly placed wellbore.[82]

Applications that call for an increase in the exposure of the reservoir to the borehole are also candidates for drilling multiple-lateral wells. This technique involves drilling more than one horizontal sidetrack from the same vertical well, at different depths or in different directions in the pay zone. Multilateral wells increase the flow potential into the borehole, though usually by less than the sum of the productivities of the individual lateral branches because of interdependent effects on reservoir pressure.[83] Until recently, a danger with

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[81] Before 1990, approximately 85 percent of all horizontal wells in the U.S. were drilled in the Austen Chalk formation. See King, *op. cit.,* p. 13.

[82] In at least one reservoir development project in the Gulf of Mexico, the cost of re-entry averaged 37 percent of the original development wells drilled from the same platform. See *Offshore,* February 1995, p. 30.

[83] J.R. Salas, P.J. Clifford, and D.P. Jenkins, “Multilateral Well Performance Prediction,” paper presented at the Western Regional Meeting of the Society of Petroleum Engineers, Anchorage, Alaska, May 22-24, 1996.

multilateral wells is that one of the branches may cone (i.e., produce water) and destroy the productivity of the entire well. To handle this situation and reduce downside risk, downhole valves have been developed that are capable of shutting in production from the contaminated branch. The valves are placed at the junctions with sidetrack branches, where they are used to monitor pressures and temperatures of inflows, and to shut off flow from branches that begin to produce water while allowing the other branches to continue production.

The benefits of horizontal wells are not achieved without cost, however. The cost of a horizontal well can run anywhere from 25 percent to 400 percent more than a conventional vertical well.[84] However, the average horizontal well also has almost twice the footage of the average vertical well (see Figure 4-1, end of this chapter). On a per foot basis, horizontal wells cost 10-20 percent more on average than vertical wells.

In addition, horizontal wells encounter greater risks than conventional wells, and require the use of more sophisticated techniques to offset those risks. The primary issue with drilling wellbores that curve laterally is the buildup of compression in the drillstring that causes increased contact with the wall of the borehole, leading to higher friction, drag, rotating torque, sinusoidal buckling, and lockup, ultimately. When the drillpipe becomes stuck, the well must be abandoned. The same risk is encountered when the horizontal section of a well traverses certain reactive shales and water is absorbed from the drilling mud, causing the clay minerals in the shale to swell. This action causes the mud and drillpipe to press tightly against the wall of the borehole. Again, the result can be a stuck pipe.

Horizontal wells require special attention to the type of drilling fluids used. As described above, drilling mud is forced down the drillstring to mix with and transport rock cuttings to the surface. When the angle of the borehole is increased, as in the case of horizontal and extended reach wells, the transport properties of the fluid are reduced. Because of gravitational physics, the cuttings tend to settle on the lower side of the borehole rather than flow up to the surface. Metal hydroxides are added to the drilling fluid to increase solid suspension properties.

The risk that the drilling mud can damage the reservoir is also increased. The greater exposure of the reservoir to the wellbore, which is the source of the benefit of horizontal wells, also means there is greater exposure of the reservoir to drilling fluids. As noted above, when the pressure exerted by drilling mud exceeds the reservoir pressure (i.e., overbalanced drilling), the mud will invade the pores of the reservoir and form a hard mud cake that must be cleaned off before production can take place. The physical properties of the formation that make the reservoir productive--porosity and permeability--also make the formation vulnerable to invasion by the drilling mud. The longer the drilling mud occupies the section of the wellbore that penetrates the reservoir, the greater the depth of invasion of the drilling mud and the more expensive it becomes to restore the productivity of the reservoir. For example, invasions that extend beyond two feet into the formation may require fracturing, which involves the injection of a large volume of liquid (such as diesel oil, water, or water with acid) into the well under high pressure to fracture the rock. The fractures are kept open after

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84 King, *op. cit.,* p. 4.

pumping has stopped by small grains of quartz, or a similar mineral, suspended in the fracturing fluid that enters the fractures and props them open.

The risk of damaging the reservoir can be avoided by underbalanced drilling--that is, where the pressure exerted on the hole by the drilling mud is slightly less than the pressure in the reservoir--but not without increasing the risk of a blowout. With underbalanced drilling, some oil and gas enters the wellbore and flows to the surface along with the drilling mud. In effect, production is occurring while the well is being drilled. Because the risk of a blowout increases in this circumstance, changes in downhole pressure are monitored closely to avoid serious accidents.

Horizontal drilling also increases the risk that other types of formation damage will leave the formation less permeable to the flow of oil and gas. For example, mechanical damage to the formation can occur because the rotation of the drill bit causes rock compression or stress concentration that reduces permeability around the wellbore. Hydraulic fracturing can be used to regain access to the formation, but fracturing can also damage the formation by creating a zone of compressed rock where the fluid is introduced. In some formations, the region around the borehole may collapse as fluids are extracted, causing a reduction in permeability. This problem is costly to remedy, making it all the more important to undertake preliminary studies to help anticipate and avoid the problem.

Drillers have learned from their experience with horizontal wells how to anticipate and mitigate many of the problems just described. Drilling fluids have been improved to reduce formation damage while at the same time they have become more effective in reducing friction on the drillstring and in well cleanup. Acid completion fluids concentrations (e.g., using hydrochloric, hydrofluoric, and formic acids) have been developed to clean up the residue (filter cake) from drilling fluids and improve formation permeability and, in fracturing applications, to cut channels into formations in order to increase porosity. At the same time, improved drilling equipment has extended the reach of horizontal wells and reduced the risk of mechanical failures. For example, longer and more powerful downhole motors increase penetration rates, while rotating stabilizers between the drill bit and motor assembly keep the assembly centered in the borehole and provide better guidance control. Thus, the costs of horizontal wells have been falling while the recognized benefits have been rising.

The increasing popularity of horizontal drilling technology is reflected in the growing percentage of wells drilled horizontally, both onshore (Figure 4-2) and offshore (Figure 4-3; both figures, end of this chapter). Over the five year period 1990-1994, the percentage of horizontal wells drilled onshore increased by a fact of 18, while the percentage drilled offshore increased by a factor of 7. Over 95 percent of the horizontal wells drilled so far are targeted to produce oil, though the number of horizontal gas wells has been increasing in recent years.[85] As of 1993, 159 horizontal gas wells have been completed, and 52 percent of them were successful.[86] The Austin Chalk formation in South Texas is the most popular location for drilling both horizontal gas wells and horizontal oil wells.

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[85] "Horizontal Gas Well Completion Technology: Survey of Industry Activity, 1972-1993," a paper prepared by S.A. Holditch and Associates, Zinc., for the Gas Research Institute, Contract No. 5093-212-2594 (November 1993), p. 6.

[86] *Ibid.,* p. 2

Horizontal drilling is less popular in the Gulf of Mexico than onshore, as indicated by the small number of offshore wells recorded in Figure 4-3. While the rate of growth in the use of horizontal techniques since 1992 is remarkable, the percentage of total wells drilled is still small. Note, however, that nearly half of the wells in the Gulf of Mexico are directionally drilled (see Figure 5-8 in Chapter 5), and directional drilling techniques are akin to horizontal drilling techniques.

IMPLICATIONS FOR PRODUCTIVITY

The pertinent economic decision is the choice between a conventional vertical well and a horizontal well. The choice will affect the cost of developing a reservoir, the amount of reserves added, and the production flow rate. Horizontal wells are generally more expensive than conventional vertical wells, although in many applications a vertical well may not be a feasible option. The new technology would increase productivity if it adds more to reserves and production than to development costs, relative to conventional technology.

As noted above, horizontal wells are useful in applications where maximum exposure of the borehole to the pay-zone is desired. Such is the case when the pay zone is thin or fractured and when permeability is low. Horizontal wells are also useful in heavy oil and enhanced oil recovery applications. In many of these applications conventional vertical wells are uneconomic, so that horizontal technology unambiguously creates new reserves and raises productivity.

The costs and productivity of horizontal wells vary considerably across different applications and in different regions. A rough rule of thumb used in the industry is that a horizontal well will produce 2 to 5 times the rate of output of a conventional well drilled in the same area.[87] Thus, in many situations one horizontal well frequently can replace between 2 and 5 vertical wells in suitable reservoirs.[88] The cost of horizontal wells exceeds that of conventional wells, though the difference has been falling over time. As recently as 1989, horizontal wells drilled into the same formation cost 4 to 8 times as much as vertical wells, but by 1993 the cost premium had fallen to a multiple of 1.2 to 1.5.[89] The smaller cost premium, combined with the reduction in the required number of development wells, shifts the cost advantage decisively in favor of horizontal technology.

The cost reductions were largely the result of "learning by doing." Operators could anticipate many of the problems encountered with horizontal drilling, as described in the preceding section, and stand by with methods for coping with them. The decline in the risks and costs naturally led to a corresponding increase in the popularity of horizontal drilling.

It is useful to survey a variety of experiences with horizontal drilling to get a better appreciation of the diversity of results. Until 1994, approximately 80 percent of all horizontal

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[87] *Offshore*, February 1995, p. 30. Also, R.M. Butler, "The Potential for Horizontal Wells for Petroleum Production," paper presented at the 39th annual meeting of the Petroleum Society of CIM, Calgary, Canada, June 1988.

[88] *Offshore*, February 1993, p. 31.

[89] *Ibid.* Note that the cost numbers given here refer to comparative horizontal and vertical wells drilled into the same formation, which differ from the average cost figures for all horizontal and vertical wells given in Figure 4-1.

wells drilled in the United States were in the Austin Chalk formation of South Texas. As noted above, the Austin Chalk is an extensive oil and gas bearing limestone characterized by vertical fractures that allowed oil and gas to migrate from below the formation up into limestone. The fractures can be accessed one at a time with conventional wells, but they provide only a limited incentive to drill because of the presence of modest amounts of hydrocarbons. A horizontal well drilled to intersect several vertical fractures at the same time offers more lucrative pay-out opportunities. The larger pay-out with horizontal wells more than compensates for the higher drilling costs relative to vertical wells.

The Giddings field is the most prolific part of the Austin Chalk formation produced to date. This 1,200 square-mile field was discovered in 1961, but its potential was not evident until after 1973, when oil prices rose and extensive field development took place. Field development declined rapidly after 1982, partly because of falling oil prices and partly because of declining flow rates. Interest was rekindled in 1984 with the possibility of drilling horizontal wells that could connect multiple vertical fracture systems with the same wellbore.

Amoco Production Company drilled 8 horizontal wells into the Giddings field during 1987-89 and compared their output rates with the production histories of vertical wells for the same period of time and with equal pressure conditions.[90] The productivity of horizontal wells relative to vertical wells is strongly correlated with the length of the horizontal portion of the borehole: horizontal completions ranging between 500 feet and 2,200 feet produced at rates between 2.5 and 7 times higher, respectively, than vertical wells.

Another review of 91 horizontal wells drilled in the Giddings field over four Texas counties found that they produced an average of 44,165 barrels of oil equivalent in the first six months or more of production.[91] Moreover, the average well paid back an estimated 60 percent (discounted at 10 percent) after-tax return on investment, and recovered drilling costs in 1.1 years. Amoco experienced the same rapid payback of investment in its Giddings field operations.[92] As is typical for horizontal wells, the rapid payback is the result of high initial production rates. Equally typical, these small reservoirs are drained fast and production rates decline rapidly.

The area with the second-most intensive application of horizontal drilling is the Mississippian Bakken formation of North Dakota and Montana. This formation is an oil shale believed to be the original source rock. Source rock means that the oil remains in the pores of the rock in which it was generated rather than, as more commonly found, in a conventional trap to which the oil has migrated from a source rock. Pacific Enterprises Oil Company reported that its Bakken horizontal wells provided a 40 percent greater return on investment than did its vertical wells in the same formation.[93]

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[90] B. A. Shelkkholeslami, B. W. Schlottman, F. A. Seidel, and D. M. Button, “Drilling and Production Aspects of Horizontal Wells in the Austin Chalk,” *Journal of Petroleum Technology,* (July 1991), p. 773-779.

[91] William T. Maloy, “Horizontal Wells Up Odds for Profit in Giddings Austin Chalk,” *Oil and Gas Journal* (February 17, 1992), p.67-70.

[92] A. D. Koen, “Horizontal Technology Helps Spark Louisiana’s Austin Chalk Trend,” *Oil and Gas Journal,* vol. 94, no. 18 (April 29, 1996), p. 19.

[93] Sandra Johnson, “Bakken Shale,” *Western World Oil* (June 1990), pp. 31-45.

The third area of concentrated application of horizontal drilling techniques is in the Prudhoe Bay field on the North Slope of Alaska. The field has been in production since 1977 and reached a peak rate of output of 2 million barrels per day (bpd) in 1988, but by 1995 output had fallen to 1.4 million bpd. ARCO's share of North Slope production, in contrast, remained flat at 400 million bpd during 1985-1995. By 1995, this level of output was 31 percent higher than the amount estimated for that year back in 1985.[94] One reason for the difference is the application of horizontal technology. ARCO discovered that there were many isolated pockets of oil remaining in the reservoir that could be exploited with horizontal wellbores. Moreover, many of the horizontal wells could be drilled as horizontal sidetracks from existing vertical wells, in order to reduce the cost of new reservoir penetrations. During 1992-1996, over half of new reservoir penetrations were drilled as sidetracks from existing vertical wells, and the average cost per well declined from $3 million to $2 million.[95] In 1997, ARCO expects to drill nearly 130 new penetrations in Prudhoe Bay, which is greater than the peak level reached in 1982, 80 percent of which will be horizontal wells. If average drilling costs had not declined from earlier levels, however, ARCO's president figures that there would be few if any wells drilled at Prudhoe Bay today.[96]

Horizontal wells are less popular in the Gulf of Mexico, particularly in high pressure turbidite reservoirs, but numerous examples exist that illustrate the benefits of using the new technology to replace conventional wells.[97] In one case, the operator drilled eight horizontal wells from a single platform to replace conventional wells suffering from water coning. The horizontal wells had average flow rates six times that of the original wells, and pair back drilling costs within two months of completion. In another case, the operator wanted to drill horizontally through two oil bearing sand lobes separated by a thin shale interval. Before re-entry, the vertical well was producing 80 b/d with a water ratio of 3:1; after recompletion, the well averaged 1,000 b/d with a 1:5 water ratio. Another operator re-entered a laminated sand formation that was abandoned after two conventional wells drilled in the 1970s produced at initial rates of 10-20 MMcfd (million cubic feet per day). A single horizontal well produced 60 Mmcfd for the first six months of production and paid off the investment in 35 days.

IMPLICATIONS FOR RESOURCE DEVELOPMENT

Horizontal wells have important resource development implications because recovery rates and extraction rates are higher than possible with conventional technology. Higher recovery and extraction rates mean that some development projects become economic with horizontal technology that were not viable with conventional technology. As a result, production occurs from prospects that would have been bypassed or abandoned before, and previously abandoned reservoirs have been revived as a result of the advent of horizontal

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94 Ken Thompson, President of ARCO Alaska, Inc., speech before the Anchorage Chamber of Commerce, April 29, 1996.

95 The term penetrations is used because many of the horizontal wells use an existing vertical well as the starting point.

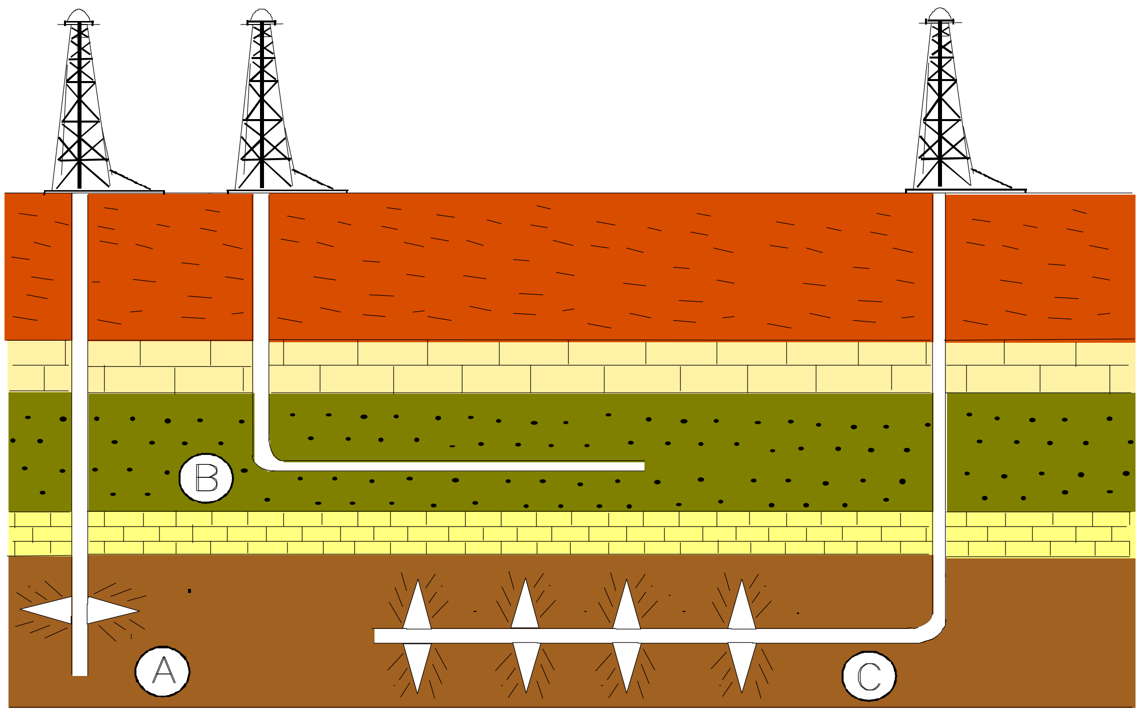
96 *Ibid.*

97 The following case histories are taken from *Offshore,* February 1995, pp. 30-32.

drilling. A higher recovery rate helps extend the productive life of known reservoirs, by delaying the date in which depletion raises production costs above expected revenues.

For these reasons, horizontal drilling technology expands the “effective” size of the resource base compared to the amount that was previously available. The new technology achieves this result by increasing the proportion of the existing stock of petroleum in the ground that can be extracted at roughly the same cost as before.

Figure 4-1
Horizontal and Vertical Wellbores

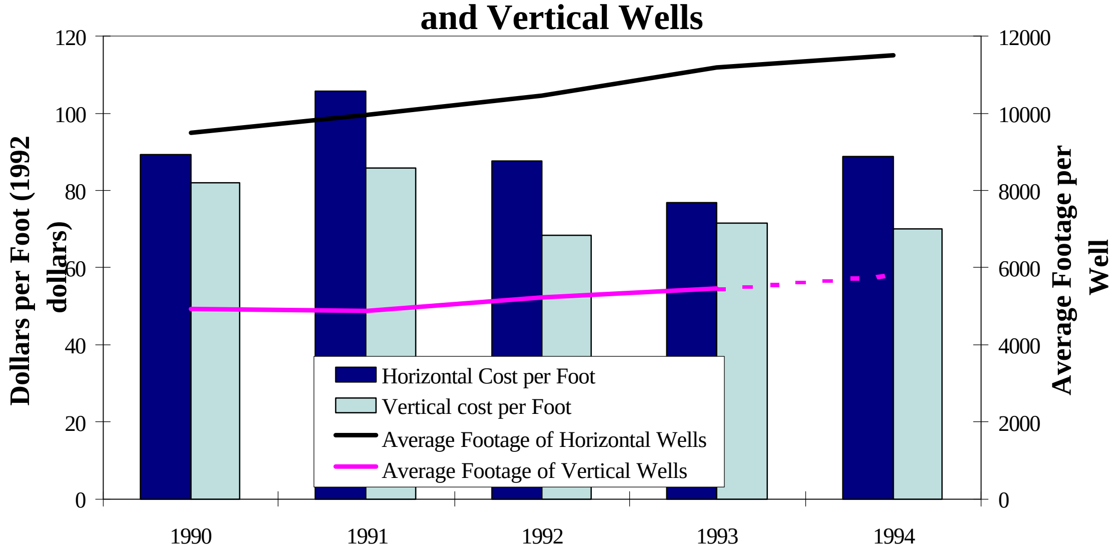


A = Vertical well, single fracture

B = Increased wellbore exposure to formation

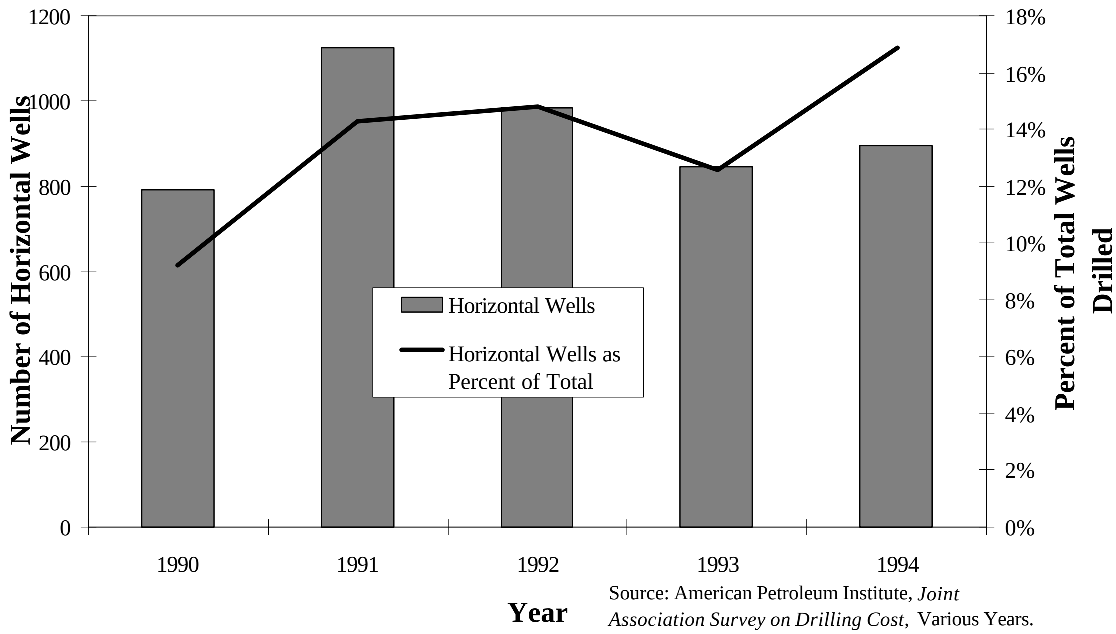
C = Multiple fractures

Figure 4-2
Average Cost per Foot and Average Footage of Horizontal and Vertical Wells



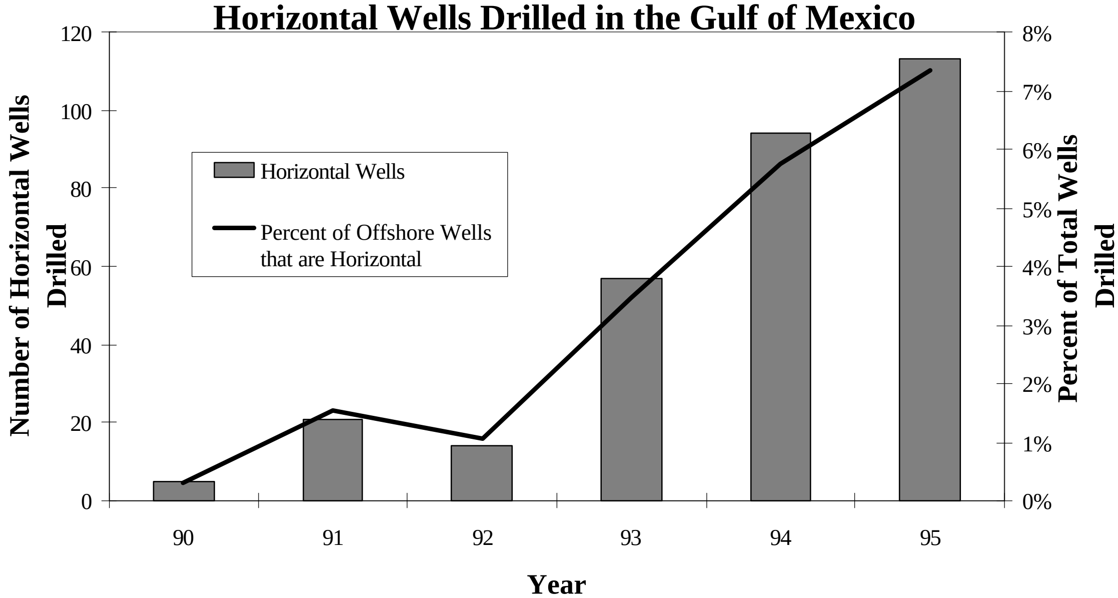
Source: American Petroleum Institute, *Joint Association Survey on Drilling Cost*, Various Years.

Figure 4-3
Number and Percentage of Onshore Horizontal Wells



Source: American Petroleum Institute, *Joint Association Survey on Drilling Cost,* Various Years.

Figure 4-4
Horizontal Wells Drilled in the Gulf of Mexico



Note: Horizontal Wells are defined as boreholes having an arc greater than 75 degree in less than 500 feet.

Source: Minerals Management Service, Gulf of Mexico Region, *Borehole Data File* [electronic file].

Chapter 5

DEEPWATER SYSTEMS: PRODUCTIVITY AND RESOURCE IMPLICATIONS

Deepwater systems refers to a collection of technologies that are used to find and develop oil and gas prospects in water deeper than 1,000 feet (300 meters).[98] These systems include, among other things, drill ships, directional drilling methods, production platforms, remote-controlled subsea wells, and subsea pipelines. Within the U.S., these technologies are used almost exclusively in the Gulf of Mexico, since other offshore areas either ban drilling (e.g., California and Florida), have no bright prospects (e.g., New England), or are shallower (e.g., Alaska).[99] The Gulf of Mexico served as the world's birthplace for offshore petroleum exploration beginning in 1947, but now accounts for only about 5 percent of total world offshore production. The other offshore basins where most activity is concentrated include the North Sea, offshore Brazil, and the South China Sea. The North Sea is the world's largest offshore producing region, though this region is not on the frontier of deepwater technology. The frontier areas are offshore Brazil and, especially, the Gulf of Mexico.

The Gulf of Mexico accounts for about 30 percent of U.S. gas production and about 15 percent of U.S. oil production (see Figure 5-1, end of this chapter). Both percentages are expected to grow in the future. At the same time, the number of exploration and development wells drilled in the Gulf of Mexico accounts for less than 4 percent of the total number drilled in the U.S. These figures reveal how much more productive the average offshore well is compared to the average onshore well.

Deepwater exploration and development is also very expensive. In recent years, outlays per project in the Gulf of Mexico have been running up to a billion dollars and more. The investment has been worthwhile, even though petroleum prices have been stagnant since 1986, because reservoirs in the Gulf of Mexico have proven to be more productive than expected. Evidence to this effect is found in the offshore lease sale conducted in April 1996, where records for the number of bids offered and the number of tracts receiving bids were set. Among the 924 tracts receiving bids, 442 were located in more than 400 meters of water, compared to 178 in the previous sale in April 1995.[100] Two characteristics mark these deepwater tracts: first, they are in waters so deep that their development will require further

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98 This is the definition of deepwater used by the Minerals Management Service.

99 The major exception is directional drilling, which is used extensively in Alaska as well as in the Gulf of Mexico. The technique is also used to drill into deposits located under environmentally sensitive areas onshore.

100 *Oil and Gas Journal*, May 6, 1996, p. 40. Interest in deepwater acreage was heightened by royalty relief legislation approved in late 1995. The legislation eliminates royalties on a certain amount of production from new leases, depending on water depth: 17.5 million barrels of oil equivalent (boe) for depths of 200-400 meters, 52.5 million boe for depths of 400-800 meters, and 87.5 million boe for water deeper than 800 meters. Nevertheless, royalty relief does not alone explain the rising competition for deepwater acreage. The previous lease sale, in April 1995, was conducted before royalty relief and drew three times the number of bids for deepwater tracts than the preceding sale in April 1994.

expansion of the frontiers of offshore technology and, second, they illustrate a strong interest in subsalt prospects.[101] Pushing the limits of technology is not new in this business, however. As of 1991, for example, 1,678 leases outstanding in the Gulf of Mexico (covering 9.5 million acres) were in water depths greater than 1500 feet, yet no production had taken place at that depth up to that time. In fact, 201 leases are in water depths greater than any production that is even planned as of 1996 (greater than 7,000 feet).

ADVANCES IN DEEPWATER TECHNOLOGY

Exploration in the deepwater Gulf of Mexico begins with the acquisition of a lease for the right to explore a tract of acreage on the U.S. outer continental shelf (OCS).[102] Blocks in the OCS are offered in periodic closed-bid auctions conducted by the U.S. Minerals Management Service, where the winner is usually determined on the basis of the highest bonus offer above a lower limit unknown to the bidder.[103] Winning bids on good prospects do not come cheap. For example, the top ten winning bids in the April 1996 lease sale went for an average of $5.6 million per tract.[104] With initial outlays of this magnitude, and the expectation of much larger outlays to undertake exploration and development, winning bidders must have very good information on which to base their offers. The primary source of this information is 3D seismic data.

Preliminary seismic information is available to all potential bidders, either from the Minerals Management Service or from one of several seismic service firms that collect the data on a speculative basis. This information is seldom adequate by itself for bidding purposes, but is used to identify prospects that are of sufficient interest to warrant undertaking a more careful 3D seismic survey. More seismic surveying may be required after lease rights have been won in order to justify a decision to go forward with exploratory drilling.[105]

Exploratory drilling in deepwater is accomplished using either a "semisubmersible" drilling platform (for water depths up to 2000 feet) or a drillship (for deeper water).[106] A semisubmersible is a platform connected to a set of flotation pontoons, where most of the flotation is positioned below sea level in order to minimize motion even in rough seas. A drillship has a drilling rig mounted amidships and a system for maintaining position over a

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[101] *Ibid.*, p. 41.

[102] In an offshore area of the U.S. the states own the mineral rights out to three nautical miles from the shoreline, except for Florida and Texas, for which the mineral rights extend out to three leagues (or nine nautical miles). The federal government owns the mineral rights from the state limit out to a water depth of 8,000 feet (2,440 meters).

[103] Deepwater leases have a ten year term (shallower leases have a five year term) in which development must take place or the lease expires. The royalty paid to the government is one-sixth of the amount of production, except for the royalty relief for deepwater leases described in footnote 100.

[104] *Ibid.*

[105] Many leases are forfeited in which no drilling has taken place, and others are forfeited because exploratory drilling does not justify development before the term expires.

[106] Drillships are currently able to drill in water up to 7,500 feet in depth, though several are under construction with a 10,000 foot capability.

drillsite. For example, the positioning system may use sound transmitted from the sea floor to an on-board computer that, in turn, engages propellers located on the bow and stern to keep the ship on station. Alternatively, a computer may use signals emitted from global positioning satellites to stay on station.

Drilling starts in the same way as described in Chapter 4, with the placement of conductor casing in the sea floor. This is large diameter pipe (e.g., up to 30 inches) that is pile driven or drilled into the sea floor for a distance of up to 250 feet, to which a blowout preventer is attached. The drilling rig is attached to the blowout preventer by a tensioned metal pipe, called a marine riser, that is around 21 inches in diameter with wall thickness approaching one inch. The drillstring (i.e., drill pipe, drill bit, downhole motor, and downhole sensory package) fits into the marine riser and, from there, into the conductor casing. Drilling mud is pumped down the drillstring, through the drill bit and downhole motor, and returns (with drill cuttings) through the annular space between the drillstring and casing, then through the marine riser to the mud pits on the rig, where it is cleaned and recycled down the hole .

If a commercial field is discovered, it may be developed using one of a variety of production platforms. In shallower water (less than 1500 feet in depth) a steel jacket platform may be used that has steel legs that piled into the sea bed.[107] Steel Jacket platforms may support a large number of production wells and associated processing facilities.[108] The on-board processing facilities separate oil from gas and water, and clean the produced water for disposal in the ocean. The oil and gas are then transported to shore via pipelines for sale.[109]

In water of moderate depth (between 1500 and 5000 feet), a “tension leg platform” (TLP) or a “floating production system” (FPS) is used.[110] The TLP floats above the offshore field and is anchored to the sea floor by hollow steel tubes, called tendons.[111] The tendons pull the buoy unit platform down in the water to prevent it from rising or falling with wave action (hence, tension legs). The wellheads and processing equipment are located on the platform, as in the case of a steel jacket platform. FPS’s are ships or semisubmersibles dedicated to production and processing operations, and are usually modified to enhance their capability to remain on station and reduce vessel motion. Whereas the steel jacket and TLP are most suitable when a reservoir can be drained from a single production center, FPS’s are used when subsea wellheads are spread over a wide area and are tied back to the FPS with flow lines.

In very deep water (beyond 5000 feet), subsea completions may be the preferred option. Subsea wellheads located on the ocean floor are connected to an underwater pipeline system to

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[107] Shell Offshore’s Bullwinkle platform, located about 150 miles south of New Orleans, is in record water depth (412 meters) for a steel jacket platform.

[108] The wellheads are located on platform so they are called “dry” trees.

[109] In other countries, tankers are used for storage and for shuttling oil to shore, but not in the U.S. because of environmental regulations. As fields become deeper and farther from shore, the cost of pipelines increases, and the restrictions on tankers will become more controversial.

[110] Shell Oil Company believes that TLP’s can be used in water depths up to 3,000 meters. See “The Offshore Challenge, Shell Briefing Service, No. 2, 1993, p. 5.

[111] As of 1996, the record depth for a TLP was Shell Offshore’s Mars platform (950 meters). The record will be broken in 1997 with Shell’s Ram-Powell platform (981 meters). Both are located in the Gulf of Mexico.

carry the oil and gas to shallower water, where a platform is located that can handle processing and shipment by pipeline to the shore. Sub-sea satellite systems are cheaper than platforms when production centers are dispersed but, unlike platforms, require mobilization of a costly floating vessel to support well re-entry for maintenance. If wellheads and pipes become plugged with sand, paraffin, or hydrates they must be cleaned out to maintain production. The processes for cleaning usually require re-entry from the surface, which is especially costly when subsea wellheads are many miles from the platform and spread over a wide area.[112]

There is an economic limit on the distance between a host production platform and satellite subsea wellheads, quite apart from the need to access pipelines and wellheads. The limit is determined by the amount of energy required to maintain the flow of oil and gas from the subsea wellhead to the host platform. The further the distance away from the platform, the greater the energy required for pumping and the more expensive the system. Shell and other companies have developed a "multiphase underwater booster system" to pump oil, gas, and water together through a single line, rather than separating these components at the seabed. An alternative approach being considered is subsea separation.

When development wells are drilled from a production platform directional drilling techniques are commonly used. Directionally drilled wells fan out from the drilling platform in different directions. Such boreholes can to reach locations in the reservoir several thousand feet from the platform in all directions.[113] Similarly, a strategically positioned platform can be used to develop separate reservoirs located over a wide area. For example, leaseblocks in the Gulf of Mexico are on average about 5 square kilometers, making it possible with current technology to drill into as many as 12 surrounding leaseblocks from the same central platform.

Offshore directional drilling uses many of the same technologies described in the last chapter on horizontal drilling. Prior to drilling, high quality seismic information is required to determine the best target locations. Drilling usually proceeds with a steerable downhole motor assembly and a "measurement-while-drilling" package. As the downhole motor and bit deepen the hole, sensors send information back to the surface on the composition of rock layers, temperature, pressure, and any fluids encountered. Seismic information about the location of the target, and downhole sensory information about the location of the drill bit as it proceeds toward the target, are so accurate that drillers can hit targets just a few feet in diameter located several thousand feet below sea floor and several thousand feet away from the platform.

The offshore operations described above impose high risks to health, safety, and the environment. Each offshore platform represents a small, isolated, artificial island where potentially explosive, flammable, and sometimes toxic material is processed under high

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112 When subsea wells are the only option and frequent well access is a necessity, it may be possible to employ a so-called "mini floater," which is essentially a small, single column TLP that can handle only a small number of wells and processing facilities. This concept has not been employed yet.

113 Wells drilled at an angle, in which the total distance of the wellbore is at least twice the vertical depth, are called "extended reach" wells. As of the beginning of 1996, the record horizontal offset is 8 kilometers, achieved in the U.K. North Sea (See *Offshore,* February 1996, p. 24). Offsets are expected to reach 10 kilometers by 2000.

pressure.[114] Consequently, special attention and considerable expense are required to mitigate the risks. All platforms have sophisticated safety control systems that automatically shut down platform operations at the first sign of trouble. Flaring of natural gas is controlled, and water produced in combination with oil or gas is treated before discharge into the sea. Emergency response plans in the case of an oil spill include the capability to call on teams of specialists and equipment that are kept in reserve for just such a purpose.

APPLICATIONS OF DEEPWATER TECHNOLOGIES

Given existing environmental constraints on exploration, the deepwater Gulf of Mexico is one of only a few areas in the U.S. that offer the opportunity of finding large, new petroleum deposits. Exploration in the Gulf of Mexico has proven that large reserves can be found, but the cost of exploration and development is very high. Without the recent advances in technology that lower costs, reduce risks, and extend the capability of the industry, these reserves would be out of reach.

All of the technologies discussed above are required to establish the practicality of deepwater exploration and production. High quality seismic information is needed to determine the probability of finding oil and gas reserves with sufficient accuracy to justify bidding for a lease and investing in exploratory drilling. The development of the reservoir depends on the ability to drill multiple extended reach wells into predetermined targets in the reservoir from a common starting point. To achieve this accuracy requires, again, high quality seismic information, and the technologies that support directional drilling. Finally, drilling and production cannot proceed without the development of platforms, drillships, and subsea systems capable of operating in deepwater.

Progress in exploring in ever deeper water has been steady since the beginning in 1947, as indicated by the increasing water depths of production platforms depicted in Figure 5-2 (end of this chapter). However, truly deepwater production did not begin until the introduction of the tension leg platform in 1989.[115] With this innovation the industry rapidly extended its depth capability. In just five years, from 1988 to 1993, the depth capability increased by 1500 feet, or by more than the entire amount achieved in the previous forty years.

As of 1996, the deepest platform in production is Shell Oil company's Mars platform, located in 2940 feet of water about 130 miles southeast of New Orleans, that commenced operations in July 1996.[116] The Mars field is estimated to contain 700 million barrels of oil equivalent, making it the largest field discovered in the Gulf of Mexico in the past 25 years. The August 1996 flow rate for one of the ten Mars production wells was 15,000 b/d, surpassing the previous deepwater production record of 13,000 b/d set by Auger (which set an

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[114] An illustration of the risks involved is the destruction of the Piper Alpha platform in the North Sea in July 1988, which claimed 167 lives.

[115] Conoco placed the first tension leg platform in service in the North Sea in 1984, but in shallower water (500 feet) to prove the concept.

[116] Information on the Mars field, and for the following two fields, comes from the Minerals Management Service, Gulf of Mexico OCS Region, *Offshore News*, November 12, 1996.

earlier water depth record 2871 feet in 1993). Mars production is expected to reach 100,000 b/d of oil and 110 MMcfd of gas by 1997.[117]

The deepest platform due to commence production in 1997 is the Ursa field, located in 4,000 feet about 130 miles southeast of New Orleans.[118] A joint effort of Shell, BP, Conoco, and Exxon, the Ursa field is the second largest discovery in the Gulf of Mexico in the past 25 years. The reservoir contains at least 400 million barrels of oil equivalent, and is expected to produce 30,000 b/d from 14 wells. This project is expected to cost $1.45 billion when completed.

The world record depth for petroleum production will be set at 5,000 feet in 1997 by Shell's Mensa field, located about 140 miles southeast of New Orleans. Unlike the records listed in Figure 5-2, where the wellheads are located on platforms above sea level, the Mensa field will be produced using 2 wellheads located on the sea floor. These wells will be tied back to an existing shallow water platform using a 68 mile pipeline. The field is estimated to contain 720 billion cubic feet of gas, and peak production will hit 300 Mmcfd in 1997. This level of production represents a 25 percent increase over Shell's total daily production from the Gulf of Mexico in 1995. Total project cost, including drilling and pipelines, is expected to total around $230 million. The Mensa project is considerably cheaper than other deepwater projects because it avoided the placement of a deepwater platform. The tieback to an existing platform was possible in this case because the gas is "dry." More common wet gas would crystallize at these depths and limit the tieback distance.

As estimate has been made of the after-tax vote of return on investment in the Auger, Mars, and Mensa projects, under fairly conservative assumptions about costs and revenues.[119] Based on announced estimates of costs and discovery sizes, a flat rack price of oil of $18 per barrel, and a rack price of gas of $1.80 per MCF, the rate of return on Auger comes to 14.8 percent, Mars comes to 29.8 percent and Mensa comes to 27.5 percent. Considering that early estimates of reserve volumes are generally very low, these profit rates are truly remarkable. It is little wonder that the industry is offering record bids for deepwater leases.

One of the technologies that makes production from deepwater economically viable is directional drilling. Many directional wells can be drilled from a single platform to underground locations that extend in all directions for several miles, thus avoiding the duplication of costly production platforms.[120] Since platform costs rise with water depth, the economic viability of some deepwater prospects may depend on the availability of this technology. It is not surprising to find, therefore, that the application of directional drilling techniques in the Gulf of Mexico increases with water depth (see Figure 5-3, end of this chapter). Over 70 percent of the

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[117] The project cost $1.2 billion to complete the first phase.

[118] In 1997, Shell is also bringing on line its Ram-Powell project using a TLP located in 3217 feet of water.

[119] Michael J.K. Craig, and Steven T. Hyde, "Deepwater Gulf of Mexico More Profitable than Previously Thought," *Oil and Gas Journal,* (March 10, 1997), pp. 45-48.

[120] Offshore enhanced recovery programs also benefit from the use of extended-reach wells. Frequently, the placement of gas and water injection wells used to drive oil toward the production wells must be located some distance from the production wells. Thus, extended-reach wells enable enhanced recovery without deploying expensive subsea wells and other facilities.

wells drilled in water depth greater than 500 feet are directional.[121] Since 1994, over 700 directional wells were drilled each year in the Gulf of Mexico, though they constitute less than half of the wells drilled in the Gulf (Figure 5-4, end of this chapter).

IMPLICATIONS FOR PRODUCTIVITY AND RESOURCE DEVELOPMENT

As expensive as the deepwater technologies may be, there is no doubt that their appearance has served to lower the average cost of deepwater exploration and development. All existing deepwater production was initiated after the decline in oil prices in 1986, and was put into place during market conditions that dictated low and stable oil prices for the foreseeable future. Thus, the changes that made exploration and production in deepwater feasible did not come from the revenue side of the equation, but from the cost side. These operations are profitable now because unit costs of finding and producing oil and gas have fallen, not because unit revenues from their sale have gone up.

The attraction of deepwater exploration is evident in the sharp rise in the average water depth of exploratory wells in the Gulf of Mexico (see Figure 5-5, end of this chapter). Over the period 1983-1995, average depth more than doubled, from less than 200 feet to more than 400 feet. The number of exploratory wells drilled in the Gulf of Mexico is down in the 1990s compared to the 1980s, but not by as much as exploratory drilling in general (recall Figure 1-10, end of Chapter 1).

The product of exploratory drilling is new discoveries, so it is not surprising to see in Figure 5-6 (end of this chapter) that the average water depth of new discoveries rose rapidly over the past ten years in the same way as exploratory drilling. The average water depth of new discoveries has more than doubled over the last decade. Also, the number of discoveries declined in the 1990s relative to the 1980s, in the same way as exploratory drilling.

The average water depth of development wells is also rising (Figure 5-7, end of this chapter), though at half the rate of increase of exploratory drilling and the depth new discoveries. Note also that the amount of development drilling did not fall off as much in the 1990s relative to the 1980s. Both characteristics are consistent with a lengthy time lag between exploratory drilling and development drilling. The time lag may be expected to increase, moreover, as average water depth rises.

The amount of production from wells located in water deeper than 1,000 feet is expanding sharply (Figures 5-8 and 5-9, end of this chapter). Oil production from deepwater wells shows a steady upward trend in recent years, in sharp contrast to production for the rest of the U.S. As a consequence, the percentage of U.S. oil production coming from deepwater wells has more than tripled over the past decade, from a little over 4 percent to nearly 14 percent of total production. Figure 5-9 shows an equally impressive surge in the percentage of total U.S. gas production coming from deepwater wells, but the share of their contribution to total production is still only 4 percent as of 1995. This share is expected to rise dramatically in the next few years.

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121 These figures include exploration as well as development wells and, as a result, understate the shares of directional development wells in deep water. Exploratory wells are more likely to be vertical than horizontal in deep water, since they are drilled from floating drillship, while development wells are typical drilled from a fixed platform.

The movement into deeper water has significantly raised the productivity of the U.S. petroleum industry, as measured by exploratory success rates (Figure 5-10, end of this chapter) and output per well (Figure 5-11, end of this chapter). The average success rate for exploratory drilling in the Gulf of Mexico is about twice that for the U.S. industry in general, and thus is responsible for boosting the overall average. The higher success rate in the Gulf helps to lower the risk of investing in more expensive offshore operations. However, while the exploratory success rate in the Gulf has risen over the past six years, it has not risen as fast as that for the U.S. in general. In particular, it is clear that Gulf operations are not alone responsible for the sharp upturn in the overall domestic success rate starting in 1993.

Output per well in the Gulf of Mexico is significantly larger in deeper water than in shallow water, and significantly improves the pay-back time for investments in deepwater. Wells located in water less than 500 feet generally produce less than 200 barrels of oil equivalent per day, while wells in water deeper than 500 feet are producing in excess of 1,000 barrels per day, a 5-fold difference. Output rates in both depth ranges rise over the 1990-1995 period, in contrast to that for the entire U.S. industry. Thus, Gulf of Mexico production has bolstered U.S. production performance, but has not been large enough to prevent the overall average from falling.

CONCLUSION

The economic viability of deepwater oil and gas prospects depends on the recent development of several deepwater technologies. It follows unambiguously that these new technologies have resulted in the creation of new reserves and in an improvement in productivity. The creation of new reserves is self-evident since the deposits would not be extracted otherwise. Productivity may be said to improve even though the cost of drilling deepwater wells is significantly higher than that for the rest of the country.[122] The reason is that the expected unit cost of additions to reserves must be lower for deepwater prospects than for those located elsewhere. Otherwise, firms would not undertake the higher costs and higher risks associated with deepwater exploration and development. The growing popularity of deepwater leases in recent OCS auctions, the increase in exploration and development expenditures in the Gulf of Mexico relative to the rest of the country, and the higher success rates and well-production rates in the Gulf of Mexico relative to the rest of the country all attest to this observation. In particular, while development costs rise with water depth, they are more than offset by larger expected additions to reserves and production rates.[123]

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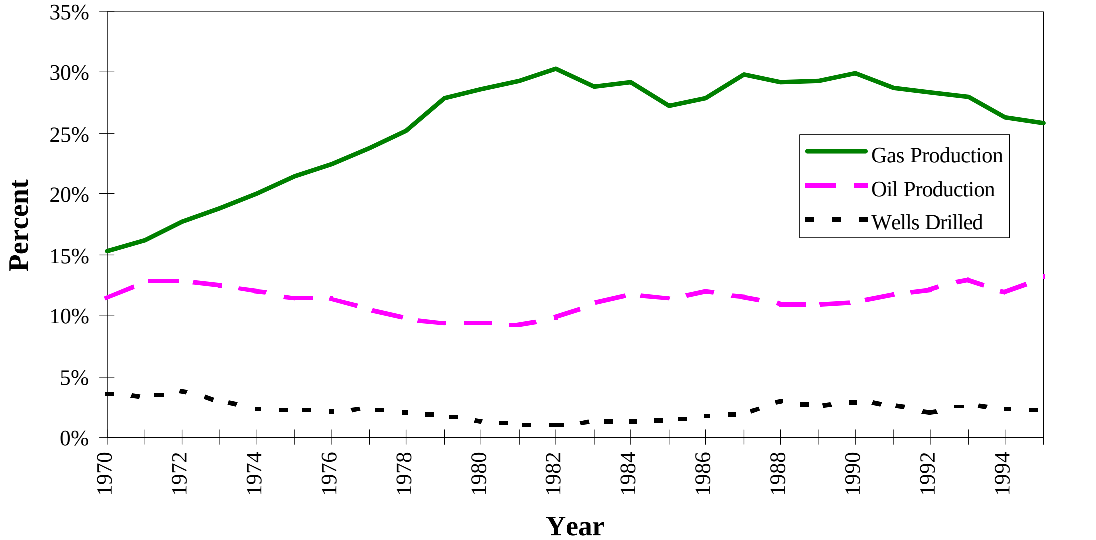
[122] A comparison of onshore and offshore development well costs (in Figure 1-9) hints at the extent of the difference between the cost of the average deepwater well and all others, since average well costs rise with water depth.

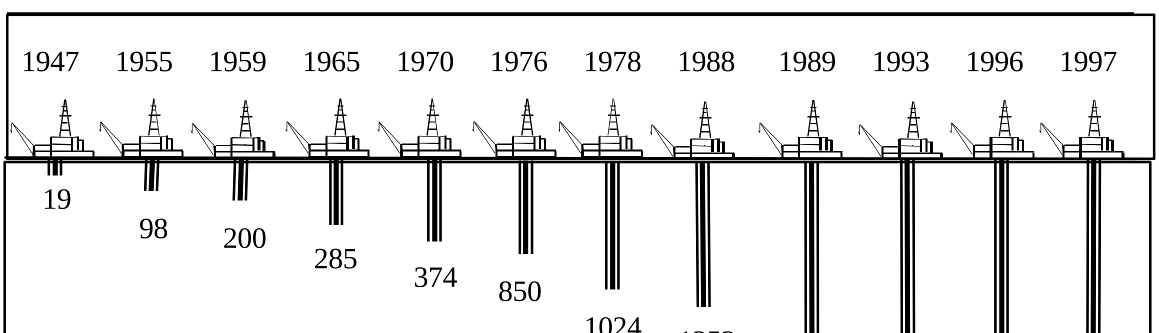
[123] The same conclusion was reached for projects located in the North Sea. See John Lohrenz and Andrew J. Bailey, “A Correlation of North Sea Oil and Gas Development Costs with Reserves, Water Depth, and Field Depth,” Research Paper 95-11, Department of Petroleum Engineering and Geosciences, Louisiana Tech University, May 1995.

Figure 5-1
Share of U.S. Petroleum Activity in the Gulf of Mexico



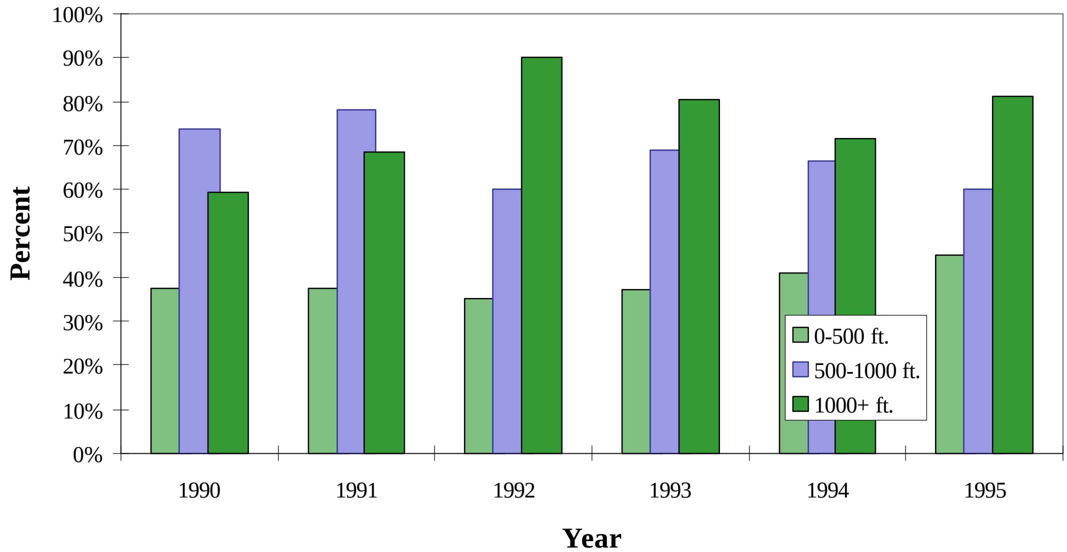
Source: Penwell Publications, *Energy Statistics Sourcebook, 1995.* Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquid Reserves Report*, 1995.

Figure 5-2
Offshore Production Platform Milestones



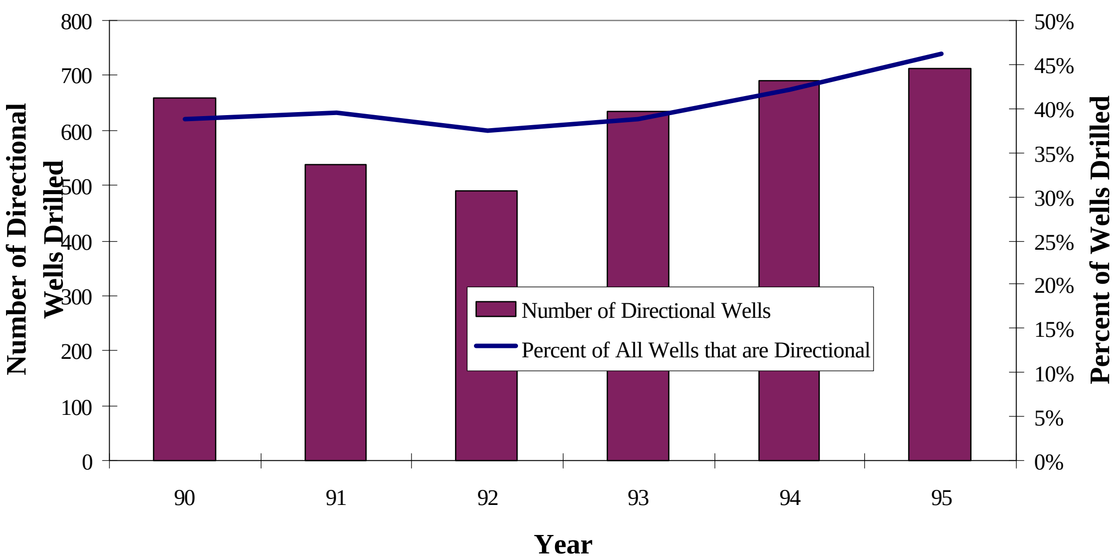
Source: Shell Briefing Service, "The Offshore Challenge, 1993, and Oil and Gas Journal, Jan 20, 1997, pg. 37-48.

Figure 5-3
Share of Directional Wells in the Gulf of Mexico, by Depth



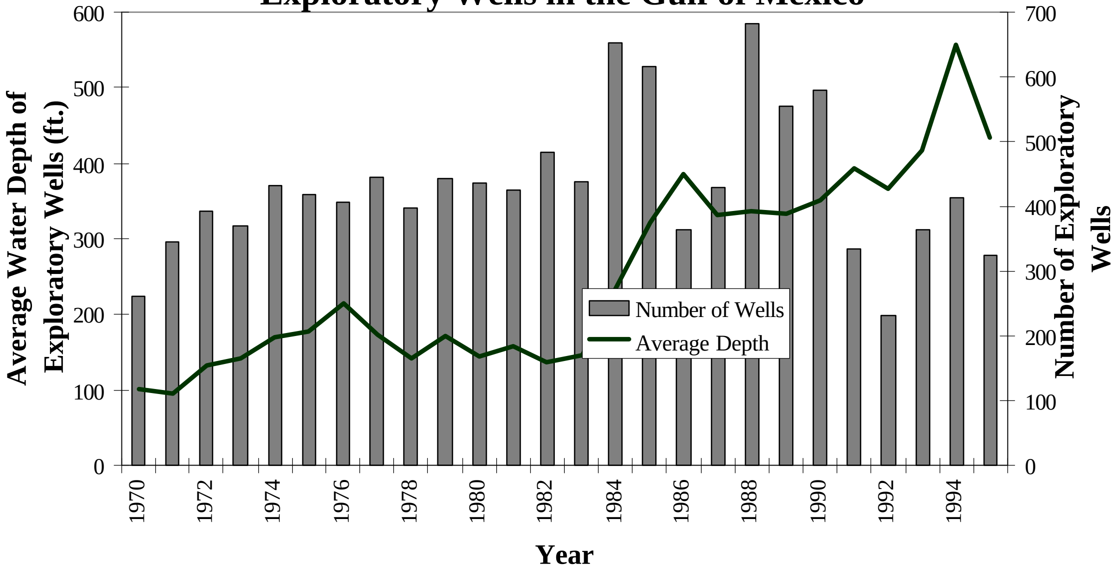
Source: Minerals Management Service, Gulf of Mexico Region *Borehole Data by Field* [electronic database].

Figure 5-4
Directional Wells Drilled in the Gulf of Mexico



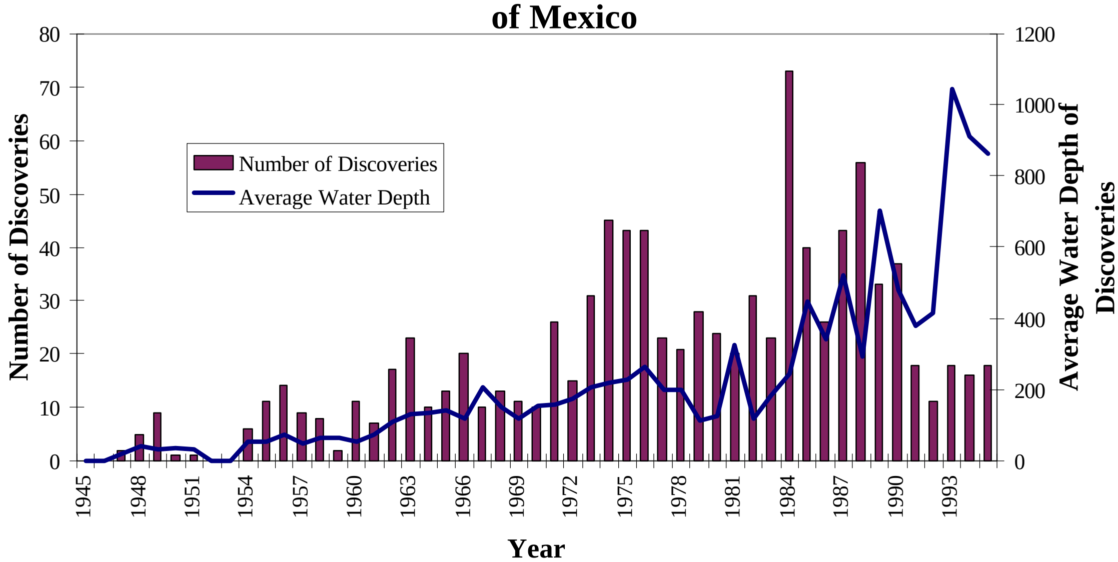
Source: Minerals Management Service, Gulf of Mexico Region, *All Well Completion Data, Detailed List*, 1996 [electronic file].

Figure 5-5
Exploratory Wells in the Gulf of Mexico



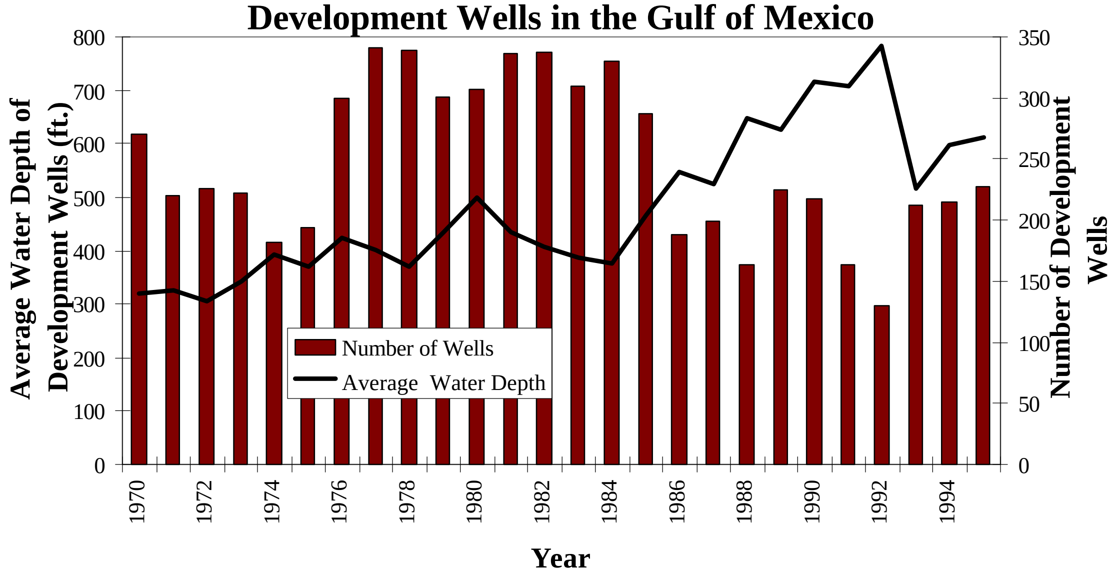
Source: Minerals Management Service, Gulf of Mexico Region, Borehole Data File, 1996; Mineral Management Service, *Exploration and Discoveries 1947-1989: An Historical Perspective*, 1992.

Figure 5-6
Average Water Depth and Number of Discoveries in the Gulf of Mexico



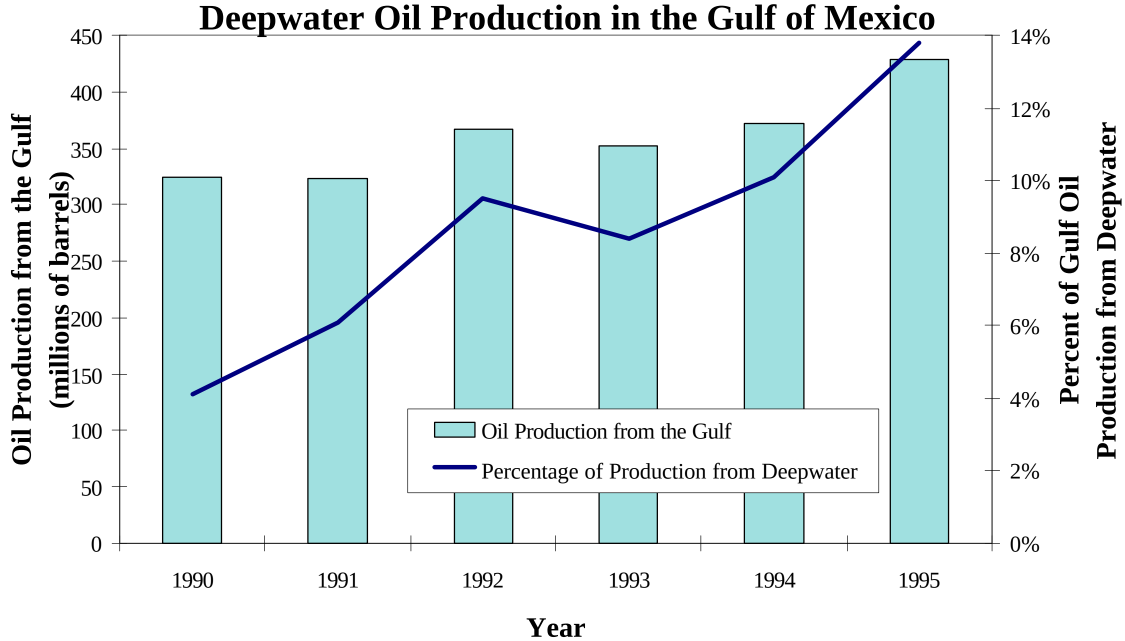
Source: Minerals Management Service, *Estimated and Proved and Unproved Oil and Gas Reserves, Gulf of Mexico*, 1996.

Figure 5-7
Development Wells in the Gulf of Mexico



Source: Minerals Management Service, Gulf of Mexico Region, Borehole Data File, 1996; Mineral Management Service, *Exploration and Discoveries 1947-1989: An Historical Perspective*, 1992.

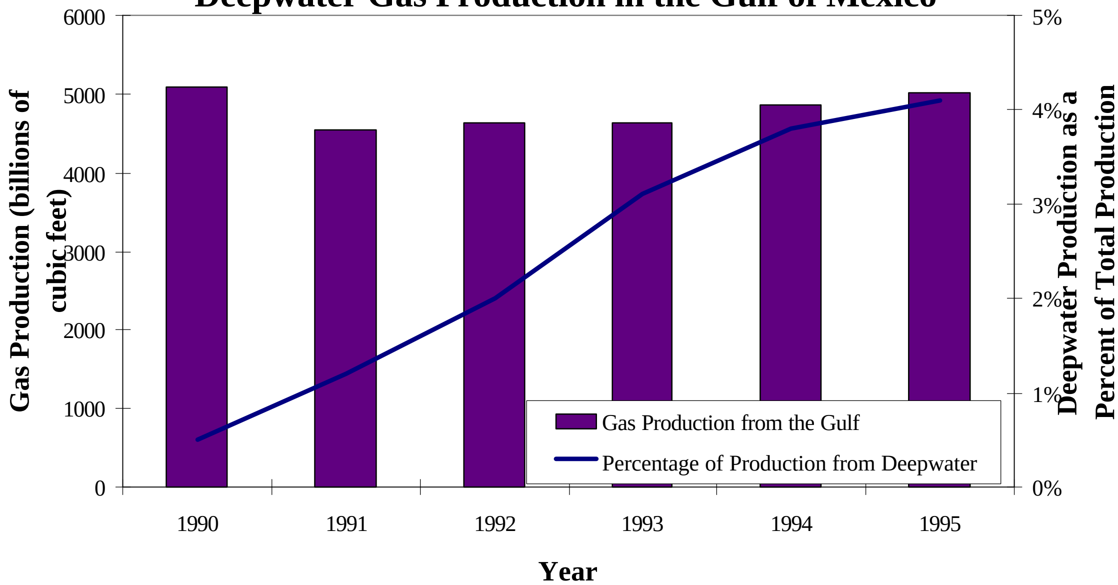
Figure 5-8
Deepwater Oil Production in the Gulf of Mexico



Note: Deepwater is defined as wells in water deeper than 1,000 ft. of depth.

Source: Minerals Management Service, Gulf of Mexico Region, *All Well Completion Data, Detailed List*, [electronic database]

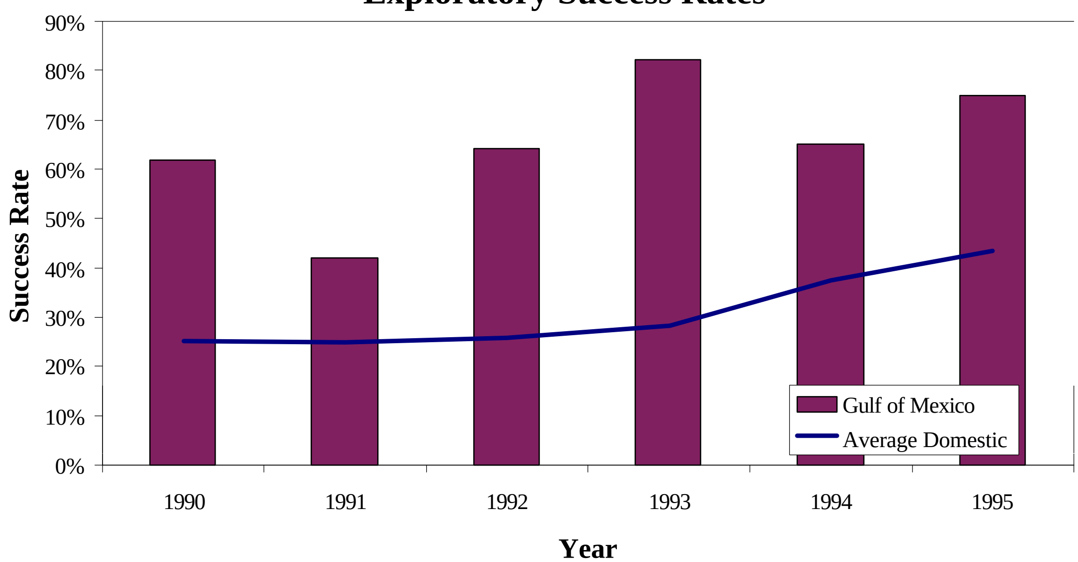
Figure 5-9
Deepwater Gas Production in the Gulf of Mexico



Note: Deepwater is defined as wells in water deeper than 1,000 ft.

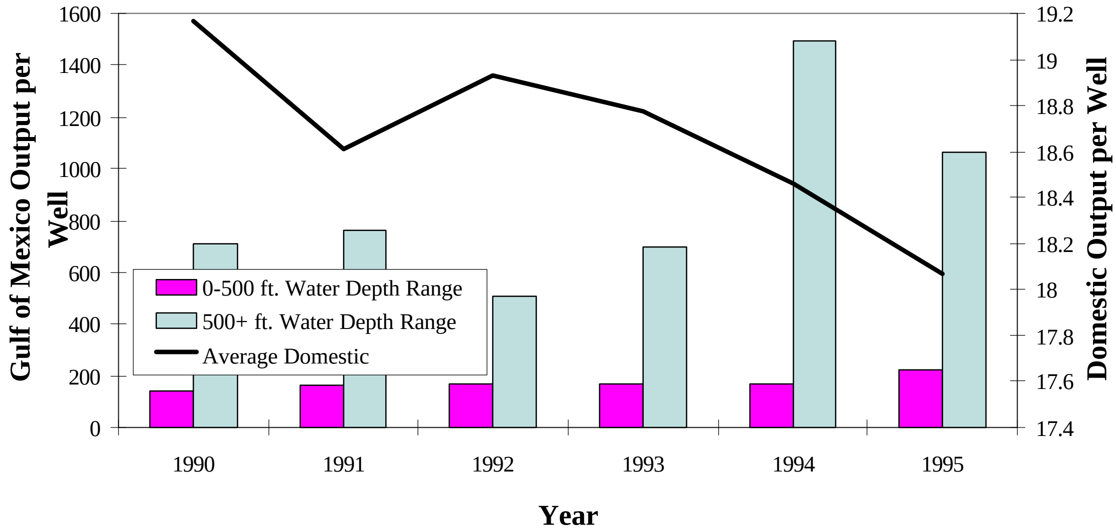
Source: Minerals Management Service, Gulf of Mexico Region; *All Well Completion Data detailed List*, [electronic database].

Figure 5-10
Exploratory Success Rates



Source: Energy Information Administration, *Annual Energy Review 1995*, July 1996. Minerals Management Service, Gulf of Mexico Region, *All Well Completion Data File* [electronic database].

Figure 5-11
Output per Well per Day



Note: Output is based on barrel of oil equivalent, where Btu is the common denominator.

Source: Energy Information Administration, *Annual Energy Review 1995* , July 1996. Minerals Management Service, All Well Completion Data File, All Well Production Data File [electronic database].

Chapter 6

ORIGINS AND IMPLICATIONS OF THE TECHNOLOGIES

Now that the contribution of three groups of technologies to the productivity of petroleum exploration and development has been established, we wish to consider where these innovations came from and where will they lead. With regard to the origins of the innovations, we are particularly interested in the events that occurred in course of their development that made them successful. What technical barriers were overcome? How quickly and pervasively were the innovations adopted by the industry? Were these technical advances achieved as a result of the effort to secure the innovation, or were they achieved independently from the innovation? Were the innovations induced by incentives to lower costs and increase profits within the petroleum industry or were they developed independently of market incentives?

With regard to the implications of these innovations, we wish to focus on the contribution they might make to the future of the U.S. petroleum industry and to conditions in the world petroleum market. Will these innovations help the upstream segments of the U.S. industry survive beyond the next twenty years? Will they make the U.S. industry any more or less competitive in the world market? To what extent will these technologies affect world oil prices? Will they alter the market power of the Middle East producers? Do they portend further technological developments and further productivity improvements?

ORIGINS OF THE TECHNOLOGIES

We begin by identifying the factors that were important to the successful development of 3D seismology, horizontal drilling, and deepwater production and then consider the extent to which the technologies are being adopted by firms in the U.S. industry and abroad. Related to the process of development is the question of whether technical innovation is endogenously or exogenously determined.

3D Seismology

The theoretical principles of 3D seismology have been known for many years, and applications of the technology were used as early as the 1970s, but practical success was not assured until the advent of parallel computing. Without increased computing power, and the corresponding reduction in the time and expense of using 3D methods, this new technology would have relegated to a marginal role in exploration and development. If 3D methods had remained on the fringe of acceptance, moreover, the complementary technologies associated with data collection and interpretation would not have been developed. Once the ability to process vast amounts of data was achieved, it then became useful to consider better ways of recording and collecting the data (e.g., multi-streamer, multi-source, multi-vessel marine technology), better ways to transmit the data (e.g., satellites), and better ways to use the data (e.g., workstation technology, analytical algorithms, and geophysical models).

The development of high performance computing did not take place independently of the needs of the petroleum industry. On the contrary, the petroleum industry has long been a major market for increased computer power, even before the advent of 3D methods, to satisfy the needs of earlier versions of reflection seismic technology. The seismological applications of increased computer power extend beyond petroleum exploration and development to include the analysis of earthquakes and the support of nuclear test detection.[124] "Seismologists were among the first scientists to exploit the capabilities of advanced computing technology."[125] The interaction between seismology and computer technology has been a two-way street. Seismologist's involvement spurred the development of new computer technology and the emergence of high-performance computing has altered the science of seismology.

Conventional digital computers consist of a memory for holding data and a processor for transforming data, these operate by repeatedly moving data back and forth between the memory and the processor as functions are performed and results are stored. The transfers back and forth limit the speed at which data can be processed. Parallel computers, in contrast, integrate the memory and processor functions by distributing memory physically throughout the computer to places where it will be needed.

The technology of parallel computing has been compared to mass production technologies in industry, where economies of scale in the processing of information are exploited in the same fashion as economies of scale in producing commodities.[126] In both cases output is increased by doing more than one thing at the same time. In data processing, three techniques are used to organize parallel activities: pipelining, functional parallelism, and data parallelism. Pipelining refers to the sequence of operations performed on the data; functional parallelism refers to, for example, separate addition and multiplication units that function concurrently; and data parallelism refers to the performance of similar operations on many elements of data at the same time.

The last technique is responsible for the massive increase in processing speed. The number of concurrent operations performed can be increased in proportion to the amount of data to be processed simply by adding more processors. That is, the speed of processing can be increased with the amount of data to be processed. Where a conventional computer takes twice as much time to process twice as much data, a parallel computer can process twice as much data in the same time by adding twice the number of processors.[127] The reduction in the time required to process seismic data is dramatic. The computer time required to process one kilometer of seismic data declined from over 800 minutes in 1985 to under 10 minutes in 1995.[128] The increased speed means that seismic surveyors can process data almost as fast as they acquire it, thus enabling them to follow-up on promising results as they occur.

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[124] National Research Council, *High-Performance Computing in Seismology* (Washington, DC: National Academy Press, 1996), Chapter 1.

[125] *Ibid.*, p. 1.

[126] W. Daniel Hillis, "What Is Massively Parallel Computing, and Why Is It Important?," *Daedalus*, vol. 121, no. 1 (1992), pp. 1-15.

[127] *Ibid.*, p. 5.

[128] E. O. Nestvold, C. B. Su, J. L. Black, and I. G. Jack, "Parallel Computing Helps 3D Depth Imaging, Processing," *Oil and Gas Journal* (October 28, 1996), p. 38.

The adoption of 3D methods within the industry is inversely correlated with the cost of using the technology, and directly related to the benefits gained as revealed from industry experience. The increased accuracy of 3D images was appreciated from the beginning, but the high initial cost of using the technology was responsible for relegating it to a development role at first. As the cost declined over time, the technology was applied more often in an exploratory role. With the growing record of experience in this dimension, the full benefits of 3D methods began to appear.

Nevertheless, even today 3D technology is not yet completely accepted by the industry. Two anecdotes support this contention. First, as revealed in the survey of Gulf of Mexico operators by Fairfield Industries (see Chapter 3), 57 percent of respondents indicated that they did not use 3D methods for exploration. The sample of responses appears to be representative of all firms operating in the Gulf, as indicated by the proportion of 3D seismic permits indicated in Figure 3-4. Care is required in interpreting these numbers, however, because it is economic to use 2D surveys as an initial screen to determine where to direct 3D surveys.

The second anecdote refers to the efforts of petroleum companies to inform themselves of the benefits they gain from using 3D methods. Some companies (e.g., Amoco) have formed special teams to analyze and publicize their company's experiences with and without the use of 3D technology. Other companies have authorized the publication of their experiences in papers delivered to professional meetings, not necessarily to benefit the profession in general, but primarily to inform the rest of the company of the results.

3D technology is as widely available in the rest of the world as it is in the U.S., but perhaps is not as widely adopted. Access to the technology is assured even if host governments and national petroleum companies abroad do not have the expertise to put it into practice. The technology may be transferred through arrangements with international petroleum companies, who may be awarded local concessions or leases for exploration and development, or through contracts with seismic service companies. The latter operate worldwide and are no less inclined to offer their services abroad than in the U.S.

Whether 3D technology is as widely adopted abroad as it is in the U.S. seems to depend on the local government and its representative national petroleum company. At one extreme, 3D technology is the standard seismic method used by Saudi Aramco for exploration and development in Saudi Arabia, regardless of the benefit-cost considerations of using cheaper 2D methods.[129] At the other extreme, 3D methods are seldom if ever used by Pemex, the Mexican national petroleum company. The difference between the two examples is largely a result of corporate cultures. Saudi Aramco prides itself in using the latest technologies throughout the production process, while Pemex is slow to adopt any changes.

Horizontal Drilling Technology

Experiments with horizontal drilling techniques date back many decades, but the practicality of the approach depended on the development of three complementary technologies: 3D seismic information so drillers would know where they wanted to place the

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129 Based on a conversation with James W. Ragland, an economist with Aramco Services Company in Washington, D.C.

borehole; steerable motor assemblies so that drillers could guide the drillstring to the target; and a downhole sensor package so that drillers would know where the drillstring was located relative to the target.

The connection between 3D seismic information and horizontal drilling is straightforward. Many applications of horizontal drilling involve small and thin deposits and high quality 3D information is necessary to locate them. In addition, detailed knowledge provided by 3D seismology about subsurface strata is necessary to guide the drillstring in the correct direction and to anticipate difficulties that might be encountered along the way. Finally, 3D surveys over time enable producers to determine the efficiency of extraction strategies or, in enhanced recovery applications, the efficiency of waterflooding and carbon dioxide flooding used to drive oil toward producing wells.

Before steerable motor assemblies made horizontal drilling more practical, “bent subs” were used on downhole motors to direct the drillstring. A bent sub is a short section of pipe with an angle machined into it that, when lowered into the borehole to the desired depth, forces the drillstring to move off at an angle. These devices were a major advance over earlier rotary drilling assemblies, but they still had their limitations. Frequent “trips” were required to change bent subs in order to control the placement of the well. Moreover, they were inaccurate; usually the angle they produced would be either too sharp or not sharp enough. The error introduced by one bent sub required an additional trip to introduce another bent sub in order to correct the error. Repeating this process creates a wellbore that tends to oscillate around the desired path, introducing unnecessary corners that add to drillstring torque and drag. Steerable motor assemblies improved directional control and reduced trip time. One motor assembly could be used for the entire directional portion of the well, thus eliminating the need to pull the drillstring to replace bent sub assemblies.

Finally, before measurement-while-drilling (MWD) packages, single-shot surveys were used to judge location of the drill bit, and they were often inaccurate. The tools were often run down the hole near the drill motor and encountered magnetic interference from the drillstring. Despite their inaccuracy, electronic instruments were not trusted in the early stages of their development. Eventually, the superiority of MWD surveys was proved and the need for single-shot surveys was eliminated. MWD tools have improved directional control, enabling drillers to intersect smaller targets and to achieve more accurate placement of the horizontal interval in the pay zone. Directional control is maintained by tying the location of the drillstring to geologic markers and to oil-water and gas-oil contacts. MWD tools also save time by eliminating the need for single-shot surveys, which stop drilling while in process.

The speed with which horizontal drilling techniques are adopted within the U.S. seems to be company-specific, region-specific, and oil-specific. The advantages of horizontal drilling are greater for oil deposits relative to gas deposits simply because reservoir conditions are more likely to impede the flow of oil to the borehole. At the same time, gas deposits present a higher risk of blowout, which is a major disadvantage to horizontal drilling relative to conventional drilling. Regionally, horizontal drilling first took off in the Austin Chalk formation of Texas, then in the Bakken Shale formation of North Dakota, and most recently in the Prudhoe Bay field in Alaska. In each case, reservoir characteristics make horizontal drilling particularly advantageous. Naturally, the companies involved in those areas are among the leaders in developing horizontal drilling techniques, the most skilled in using the technology, and the most aware of the advantages to be gained.

The first two factors mentioned, access to the latest technology and the skill to use it, can be purchased from drilling service companies, many of which work under contract to operators in each region mentioned above. What cannot be purchased as easily is knowledge about the efficacy of the technology in new situations and a corporate willingness to try new approaches. The same considerations slow the transfer of this technology to other countries. Like 3D methods, horizontal drilling technology is available anywhere in the world through service contracts with drilling contractors. Moreover, the technology is readily adopted in areas (e.g., North Sea) where there are recognized advantages. Having more specialized applications than 3D, however, horizontal drilling technology is likely to spread more slowly through the industry and abroad.

Deepwater Systems

The industry's capability to produce oil and gas from deposits located underneath water has developed gradually since 1947, as indicated by the steady increase in offshore platform depths recorded in Figure 5-2. Although the process of development has involved many separate technologies, three pivotal innovations mark a turning point in the industry's capability to operate in deepwater: 3D seismology, directional drilling, and production platform design.

3D seismology was important to deepwater exploration because it provided more accurate estimates of subsurface configurations and, ultimately, the magnitude of reserve potential. This information helped to justify the enormous capital investments needed for deepwater production facilities.

Directional drilling, as described in Chapter 5, enables operators to drill multiple production wells from the same production platform, fanning them out from the platform in different directions to hit targets in different parts of the reservoir or in different reservoirs. The practical success of directional drilling was achieved by the development of the same technologies used for horizontal drilling: 3D seismic information, steerable downhole motors, and downhole sensors.

Implementation of the "tension leg platform" system, and similar floating platforms,[130] extended the water depth limit far beyond that of steel jacket platforms. Steel jacket platforms are massive steel towers that rest on the seafloor. Their economic depth limit is imposed by the amount of steel required to support the tower and surface equipment. The tallest steel jacket is "Bullwinkle" platform, located about 150 miles south of New Orleans in 1353 feet of water. This platform is considered the economic limit for steel jackets.

The first tension leg platform (TLP) placed in the Gulf of Mexico was Conoco's Jolliet platform, erected in 1989 in 1760 feet of water. Five years later, in 1994, Shell inaugurated the Auger platform in 2860 feet of water. Thus, between the building of the Bullwinkle platform 1988 and the Auger platform in 1994, the water depth record was

[130] Other floating platforms are SPARS, compliant towers, and semisubmersibles.

extended by 1510 feet, or by more than that achieved in the previous forty years of building steel jacket platforms.

The additional depth achieved by TLP systems finally helped narrow the gap between the water depth capability of exploratory drilling and the water depth capability of development (and therefore production) drilling. As early as 1976, operators were capable of drilling exploratory wells in more than 3,000 feet of water, yet the production platform depth record for that year was 850 feet.[131] Twenty-one years later, in 1997, the depth of production platforms finally reached beyond 3,000 feet. By 1984, an exploratory well was drilled by Shell to 6952 feet off the coast of New Jersey, though 12 years later no production is contemplated at that depth except by subsea completion. However, subsea wells are feasible only if a production platform can be located close enough to the wells to make it possible to process the output.

Deepwater platform technology has been adopted only by a few firms that have made the financial commitment to develop deepwater prospects. The world leader in this technology is Shell Oil Company.[132] Shell's successes in the Gulf, several of which were undertaken with multiple partners, have provided the lead that others are beginning to follow.[133]

IMPLICATIONS OF THE NEW TECHNOLOGIES

This section addresses the implications of the three new technologies for the world oil market, including the competitiveness of petroleum production in the U.S. and the behavior of the world price of oil. Similar considerations are not important with regard to natural gas because the high cost of processing and transporting liquefied natural gas reduces the importance of international competition for the U.S. gas market.[134] For the same reason, the price of gas in the U.S. is not determined by worldwide gas supply and demand conditions in the same way as the domestic price of oil.

Competitiveness of the U.S. Petroleum Industry

The introduction of 3D seismic methods, horizontal drilling and deepwater production technologies have all improved the competitive position of the U.S. petroleum industry in the world market. To assess their effect on the U.S. competitive position, it is most important to determine how the technologies affect profit margins in the U.S. relative to profit margins in low-cost producing areas. The low cost producers are used for comparison because their production decisions determine how much of the world market they will share with high-cost producers.

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131 Early drilling records may be found in *Oil and Gas Technologies for the Arctic and Deepwater* (Washington, DC: U.S. Congress, Office of Technology Assessment, OTA-O-270, May 1985).

132 A close rival in this regard is PetroBras of Brazil.

133 As of 1996, Shell ranks number one among operators in the Gulf in terms of acreage held, producing acreage, wells drilled, and production, both in deepwater and in all depths. See *Offshore* (January 1997), p. 44 ff.

134 The U.S. imports gas by pipeline from Canada and, potentially, from Mexico.

3D technology, in particular, has significantly reduced the cost of adding reserves through exploration and development. Although the same technology is equally available in the rest of the world, the impact on profit margins is more important in high-cost areas such as the U.S. than in low-cost areas such as the Persian Gulf. Because profit margins are determined by the difference between the world price of oil and the local production costs, they are narrower for firms operating in high-cost areas than in low cost areas. A 40 percent reduction in finding costs, even if it applied evenly around the world, is important when finding costs are several dollars and not important when they amount to no more than a few cents per barrel. Additionally, the impact of 3D is likely to be less dramatic in prolific areas such as the Persian Gulf than in less well-endowed environments. Thus, the impact of 3D seismology on profit margins may be considered relatively small in low-cost countries and relatively large in high-cost countries. It follows that competitiveness of the U.S. and other high cost areas should improve relative to the Persian Gulf and most other oil exporting countries. Thus, the new technology will help to sustain the petroleum industries in the U.S. and other high-cost countries.

Horizontal drilling and deepwater technologies will also help bolster U.S. profit margins. Both technologies extend the effective size of the domestic resource base that is economic to exploit at the world price of oil. Horizontal drilling achieves this gain largely by increasing the amount of oil that can be profitably extracted from mature and abandoned fields. Deepwater technologies achieve the same benefit by extending the number of new fields that can be profitably exploited, and by increasing the average size of fields discovered.

Both sets of technologies are available anywhere in the world, but do not necessarily have the same impact on profits abroad as in the U.S. In particular, horizontal drilling and deepwater technologies are important in the North Sea. Brazil, West Africa, Southeast Asia, and Caspian Sea, but not in the Persian Gulf. Horizontal drilling is less important in the Persian Gulf because the resource base has not been depleted to the point where it is worthwhile to re-enter or rework older fields. Higher earnings can be achieved by putting investments into new reservoirs or in developing existing reservoirs more fully. Also, deepwater technology will never be applicable in the Persian Gulf because of shallow waters.

Implications for the World Price of Oil

Although 3D seismology, horizontal drilling, and deepwater technologies lower production costs in the U.S., raise domestic output relative to what it would have been, and have similar effects in other producing countries, these technologies are not likely to have a major impact on the world price of oil. This conclusion is perhaps self-evident in the case of horizontal drilling and deepwater production because they do not affect a large enough share of world production.[135] 3D seismic technology is another story because it has a dramatic effect on finding cost worldwide. Nevertheless, the expected impact on the price of oil will be so small that it will be hard to detect in recorded price data. The reason is that the reduction in production costs is a small fraction of the world price.

[135] For example, using data shown in Figures 5-1 and 5-8, deepwater production in the U.S. contributed only 1.8 percent of annual U.S. oil output in 1995, or about 0.2 percent of world production.

To demonstrate the argument, suppose that 3D results in a 40 percent reduction in average finding costs worldwide.[136] Since average finding costs of major oil companies average between $4 and $5 per barrel, according to estimates by Arthur Anderson, it follows that 3D can reduce total costs by as much as $2 per barrel.[137] The potential reduction in price would therefore be, at most, $2 per barrel.[138]

During 1986-1995, the average monthly world price fluctuated about a mean of $18.30 with a standard deviation of $5.77.[139] By comparison, a $2 per barrel reduction in the price because of 3D amounts to slightly over 10 percent of the average world price and about a third of the standard deviation. The magnitude of the effect of 3D seismology on the price is therefore modest relative to the many other market factors that cause fluctuations in the world price. Thus, the effect of 3D technology would be lost in the noise caused by the other factors that influence the price.

Perhaps more important than the effect of 3D on the price level is the effect on price variation. The reduction in finding costs, as noted in the last section, is more important to high cost producers than low cost producers. The low cost producers, moreover, are dominated by the members of OPEC, and especially those located in the Persian Gulf. The high cost producing countries are a collection of independent producers with relatively small levels of output. This group of producing countries may be characterized as the "competitive fringe" in the oil market. Their presence limits the ability of the dominant firms to raise the market price because of the responsiveness of output to increases in the price. Output is price sensitive because of the narrow profit margins that characterize production. An increase in the price or reduction in costs, also expands the range of prospects that becomes economic to exploit. The same considerations imply that the high-cost producers also play a price stabilizing role in the market. High prices mean greater output that, in turn, reduces the price; low prices mean that some production must cease, which bolsters the price.

[136] Recall from Chapter 3 that only a fraction (perhaps less than 40 percent) of exploration and development in the U.S. uses 3D seismic methods, and that the fraction is even smaller in the rest of the world.

[137] Arthur Anderson, *Oil and Gas Reserve Disclosures,* 1994.

[138] The maximum price effect assumes that the price elasticity of supply of oil is infinitely elastic and that the price elasticity of demand is zero. A supply elasticity less than infinity or a demand elasticity less than zero will creating offsetting effects following the reduction in finding costs that will reduce the price effect to less than $2 per barrel.

[139] The price series is the average monthly F.o.b. cost of imported oil, as reported in Energy Information Administration, *Energy Infodisc,* Petroleum Marketing Series, 1996.