Can the U.S. Oil and Gas Resource Base Support Sustained Production?

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Aggressive drilling for oil and gas in the lower 48 states of the United States over the past decade yielded reserve additions sufficient to arrest decline and to stabilize levels of production. Such positive response from a maturely explored and developed oil resource base was unpredicted and largely unanticipated. Two elements of the recent experience—maintenance of stable rates of finding and substantial levels of conventional reserve growth in older fields—indicate that the capability of the resource base to sustain production is yet considerable. The volume of domestic oil and gas production that is necessary in the national interest and the extent to which the resource base should be pursued are the central issues of public energy policy.

NEARLY 3 MILLION WELLS HAVE BEEN DRILLED IN THE search for and development of oil and natural gas in the United States, making most of the nation's oil and gas provinces among the most thoroughly explored and developed in the world. On land, at least, nearly all of the very large oil fields have long been discovered. In the lower 48 states of the United States more than 2.5 billion feet (7.6×10^8 m) of exploratory hole has been drilled. The first 0.5 billion feet of that effort yielded 70% of the oil and natural gas discovered to date. The balance—about 80% of historical drilling effort—has been in pursuit of the remaining 30%. By any comparative measure, U.S. oil and gas resources have been explored and exploited to a mature stage. The remaining oil and gas resource is marginal, not because it is significantly limited in size, but because it can only be converted to producible reserves in relatively small increments. Is it in the national interest to pursue this ample though marginal resource to a significant or even aggressive extent, or should it be concluded that U.S. production of oil and gas is rapidly becoming a piece of history?

The early finding of large and giant fields and the later discovery of smaller fields are a discovery pattern seen in oil and gas provinces worldwide. This pattern is mirrored in the geological and geographic distribution of oil and gas, in which the principal volumes have been found in a very few of the world's largest fields and the balance exists in an extensive universe of smaller fields. It is the few large fields, with their ample, flush, and low-cost production that have long dominated the perception of oil as a resource. The peak times for the discovery of giant fields in the United States in the 1950s and of production in 1972 led to the common statistical characterization of oil discovery and production as rather symmetrical life-cycle events. In these characterizations, discovery and production increased exponentially (*1*), but once in decline they would continue to decline and to decline exponentially. Discovery and production from the universe of smaller, more marginal fields or increased recovery from older, larger fields would not and could not change the pattern significantly. Through combinations of public policy and perceived necessity, the maturely exploited oil and gas resource base in the United States nonetheless has been pursued, and, with the higher oil and gas prices of the past decade, it has been pursued aggressively. As a result the United States has drilled 85% of the oil and gas wells of the non-Communist world and has developed, uniquely, a large sector of low-overhead, small company and independent operators geared for the pursuit of resources that could be discovered and produced only in relatively small increments. The major U.S. companies have also pursued the more attractive parts of this marginal resource.

The response of the oil and gas resource base to the extensive exploration and extended development during the past decade in the lower 48 states of the United States was significantly greater than anticipated. With increased drilling, in part a response to higher prices, annual reserve additions that had been generally declining since the mid-1960s began to trend upward at about the same rate as the rate of drilling increase. From 1979 through 1985, average annual reserve additions essentially matched production levels. Oil production decline, which began in 1973 and was almost universally expected to continue to decline, was arrested, and stable levels of production were maintained through 1985, before the drastic drop in prices and drilling effort in 1986.

Were the increases in reserves and the stabilization of production minor perturbations of the conventionally held symmetrical life-cycle patterns, or did they signal characteristics of marginal resources not appreciated previously? Could the maturely explored oil and gas resource base of the lower 48 states continue, for some extended period, to provide additions sufficient to maintain stable production if it were pursued, for example, at a level of drilling experienced in the early 1980s? Conclusive answers may have to await the return of prices sufficient to spur intensive drilling again; however, at least two aspects of the recent experience indicate that the capability of the U.S. resource base to sustain production should be reconsidered.

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1) The rate of oil and gas finding, expressed in volumes discovered per foot of exploratory drilling, decreases with cumulative drilling but remains stable through extended, and increasingly greater, intervals of drilling. This premise contrasts with the conventional assumption that rate of finding declines exponentially with continued drilling.

2) The amount of additional reserve growth available from existing, older, and generally larger fields through extended conventional development and recovery techniques was much greater than expected from historically calculated growth factors.

Discovery of New Fields

The rate of finding for oil and gas generally decreases as exploration effort proceeds because in the discovery pattern in most provinces the majority of the largest finds are made early. The conventional view held was that declines in finding after early discoveries of large fields would continue at exponential rates. Yet recent studies point to stable levels of discovery (*2, 3*). Plots of finding rates against cumulative exploratory drilling through more than 2.5 billion feet of drilling (Fig. 1) indicate that finding rates decrease through successive stages but that those stages maintain stable rates and extend through progressively greater intervals of drilling effort.

The significance of stable rates of finding, as opposed to exponential decline, is illustrated by recent experience in natural gas discovery (*4*) (Fig. 2). In this case future discovery was projected by extending the exponential decline curve forward from a cumulative exploratory drilling point of 1.8 billion feet. Such a projection indicated discovery of about 85 trillion cubic feet of natural gas during the drilling of the next 800 million feet of exploratory hole. The actual volume of discovery from 1978 through 1985, the period of the projected drilling interval, was 70% greater than projected because the rate of finding remained stable.

The second stage of exploratory drilling (Fig. 1), with a finding rate of about 80 barrels of oil equivalent (BOE) per foot (1 barrel is 159 liters), persisted through the drilling of about 1 billion feet, twice the extent of the first stage, when 345 BOE per exploratory foot were discovered. The third stage, with a finding rate of about 42 BOE per foot, has persisted through about 1 billion feet of exploratory drilling, and will most likely be maintained through a substantial additional exploratory effort.

The calculated stable rates of finding and the observed progressive increases in extent of exploratory stages with successively lower rates of finding relate closely not only to the basic progression of discovery patterns but also to the size distribution of fields historically discovered or presumed yet to be discovered. The highest rates of finding coincide with the initial discovery of large fields; successively lower rates of finding occur as the smaller fields are discovered. The number of discovered fields increases geometrically with decreases in field size. Thus, distinct exploration stages with lower rates of finding develop as the universe of smaller fields is explored and discovered.

The pursuit of marginal, smaller fields has resulted in the discovery of more than 25,000 small fields in the United States. About half of all fields discovered before 1975 held less than 1 million BOE each (*5*) (Fig. 3). Since 1975, these small fields have represented 85% of the fields discovered; nearly 97% of all fields discovered since 1975 contain less than 10 million barrels of oil and gas equivalent.

Statistical analysis indicates that the remaining number of small and modest-size fields is very large (*6*). As shown in Fig. 3, the number of fields discovered increases substantially with decrease in field size through field size C (10 to 25 million barrels); the numbers essentially level off through the smaller field sizes D and E. Statistical analysis of field size distribution over time of exploration effort and comparison of size distribution in basins with different costs of finding and producing indicate the truncation of smaller field size is economic and not geologic (*6*). The size mode shifts progressively to smaller fields as the cost to find, develop, and produce decreases (Fig. 4). If the truncation is economic rather than geologic, the number of small and modest-size fields (250,000 to 10 million BOE) remaining for discovery in the oil and gas provinces of the lower 48 states of the United States could be well in excess of 100,000.

If the remaining volumes of conventionally recoverable, yet-to-be-discovered U.S. resources are on the order of 40 billion barrels (Bbbl) of oil and 400 trillion cubic feet of natural gas, as generally estimated, and if a large number of remaining fields are small in size as projected, rates of finding during the present exploratory stages should persist through the drilling of an additional 2 billion feet of

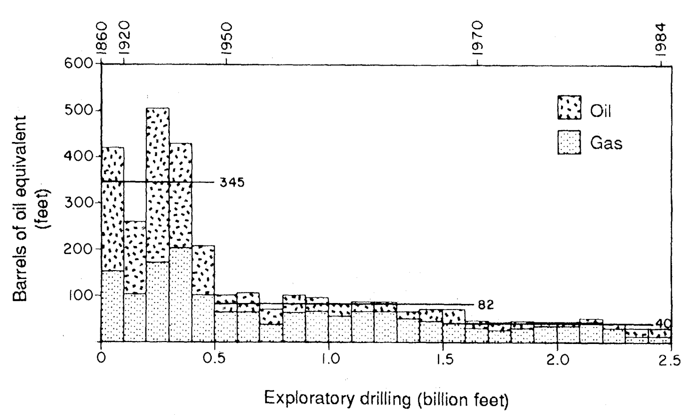

Fig. 1. Historical discovery of oil and natural gas in the lower 48 states of the United States.

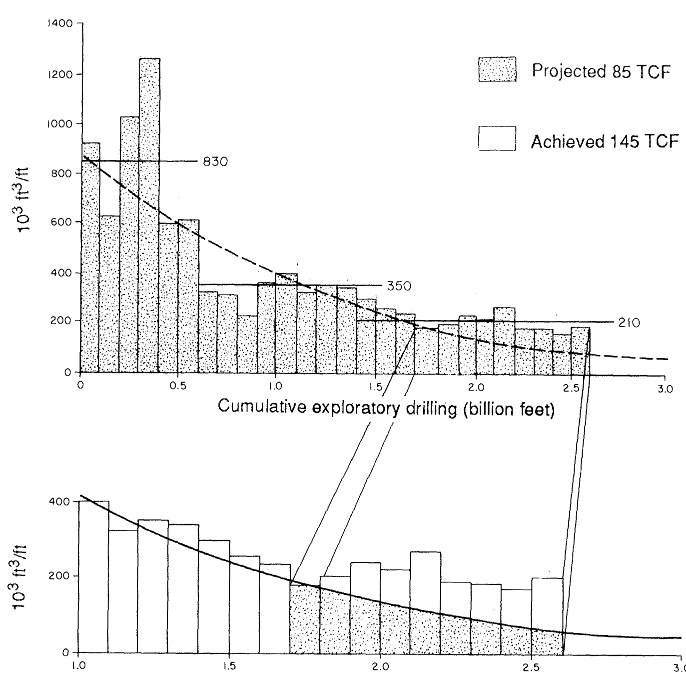

Fig. 2. Actual discovery compared to discovery projected by exponential decline from 1.7 through 2.5 billion feet of exploratory drilling; TCF, trillion cubic feet. [Data from (*4*) modified and updated]

exploratory hole. The remaining, yet-to-be-discovered U.S. oil and gas resources could thus support levels of drilling with finds achieved during the 1970s and early 1980s for a 30-year period. Beyond this stage, a somewhat lower rate of finding, about 15 to 20 BOE per exploratory foot, could be maintained through several billion feet of additional exploratory drilling, should fields with total reserves of 10,000 to 100,000 barrels be economic to pursue. Economic cutoffs extending to fields of such size would enlarge current estimates of yet-to-be-discovered oil and gas.

The stability of rate of finding is a critical factor in reassessing both the capability of maturely explored resources to sustain production and the expected costs to develop these resources. The concept of ever-increasing costs to discover is probably not applicable since the stable rate of finding indicates that exploration of an extensively developed resource base can continue to provide reserve additions equal to recent levels.

As critical as the discovery of new fields is, it has not been a volumetrically major factor in reserve additions in the lower 48 states in recent years, nor is it likely to be in the future. Since the late 1970s, oil discoveries (with expected appreciation) have amounted to about 500 million barrels annually, with about equal contributions from on land and offshore. These additions have represented only slightly more than 15% of annual levels of total production and less than 10% of total on-land production of the lower 48 states.

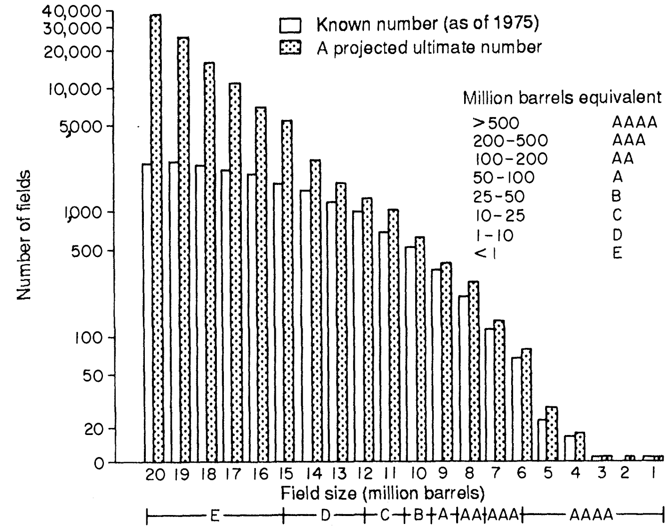

Fig. 3. Known and projected size distributions of oil and gas fields in the lower 48 states. Numbers 20 to 1 indicate relative field size. [Modified from (*5*)]

Reserve Growth

As the U.S. resource base has been pursued to an advanced stage, the principal source of oil reserve additions has been reserve growth in older, large fields, rather than discovery of new fields. The traditional sources of reserve growth are "new-pool" discoveries to enlarge vertically and extension drilling to enlarge areally the boundaries of fields. But, in recent years the principal contribution of oil reserve growth has been intensive drilling within fields, or so-called infill drilling. New-pool discovery and extension drilling remain the principal sources of reserve growth in gas fields, although substantial evidence indicates infill drilling in gas fields could provide a major source of gas reserve growth.

The emergence of infill drilling in older fields as a major source of oil reserve additions in recent years was largely unexpected. The conventional view of oil production was a progression through primary, or initial, recovery to secondary recovery, where water was commonly injected to flood the reservoir. The oil remaining after primary and secondary recovery was judged to be residual, or nonmobile, and additional recovery was possible only through application of costly tertiary techniques to make the oil mobile. Infill drilling, it was held, would increase production over a shorter field life but would not add reserves.

The implication of this view, as indeed the traditional assumption that reservoirs are thoroughly drained by the drilling of uniformly spaced development wells, is that reservoirs are essentially homogeneous and drain uniformly. Certain reservoirs are quite homogeneous, and, where a strong drive mechanism exists, uniform drainage has resulted in high recovery of original oil in place. The East Texas field is a prime, but also unique, example. With a homogeneous reservoir, a strong water drive and maintained pressure, and a drilling density that averages one well to 4.5 acres (1.8 hectares), essentially all the mobile, nonresidual oil in the East Texas field will be recovered, giving an overall primary plus secondary recovery of 86% of the original oil in place. With the volume of residual oil after sweep (that is, after thorough flooding by water) amounting to 14%, virtually all mobile oil will be recovered. Much lower recovery factors, however, are the rule, with some reservoirs yielding no more than 5% of original oil in place, so that the average recovery efficiency of all reservoirs at the present level of development is only about 35% of the original oil in place.

Theoretically, if a reservoir is homogeneous and its contained fluids behave uniformly, a specified and uniform spacing of wells should result in uniform drainage; flooding with either a natural water drive or the injection of water in secondary flooding should effectively sweep the entire reservoir, leaving only immobile, residual oil. However, determination of residual oil concentrations in swept portions of reservoirs shows values substantially lower than volumes estimated to remain and as such implies a much higher recovery efficiency than is in fact generally achieved. For example, residual oil concentration in a swept portion of a reservoir might be

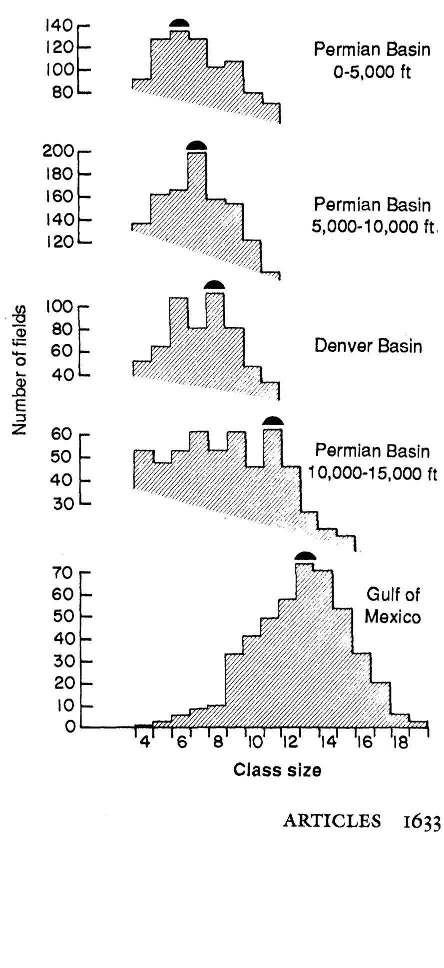

Fig. 4. Class size distribution by basin and depth. The Permian Basin at 0 to 5000 feet is shown as having the lowest cost to find, develop, and produce oil and gas, with the Gulf of Mexico having the highest cost. Numbers 4 to 18 indicate relative class size. [Adapted from (*6*). Courtesy of the International Association for Mathematical Geology]

an amount equal to 30% of original oil in place. If the reservoir were uniformly swept, primary and secondary recovery should amount to 70% of the oil in place; commonly the projected ultimate primary and secondary recovery is only 30% or less. Forty percent or more of the mobile, nonresidual oil is thus not recovered. Analysis of residual oil concentrations in swept portions of reservoirs, original oil in place volumes, and currently expected ultimate oil recovery volumes of the major reservoirs of Texas and the United States shows that an average of only about 60% of mobile oil originally in place in contrast to total oil originally in place will be recovered with existing levels of development. This level of recovery implies that if all reservoirs were thoroughly swept, as the assumption of uniform drainage calls for, average recovery efficiencies of original oil in place should be about 55% instead of 35%. The percentage of mobile, nonresidual oil recovered out of the total in place volume of mobile oil, with existing development, ranges from no more than 15% in such geologically complex reservoirs as the Spraberry turbidites of West Texas to about 90% or more in homogeneous wave-dominated deltaic deposits of the Woodbine of East Texas. At given levels of well spacing and with given levels of flooding, either primary or secondary, the percentage of mobile oil recoverable with existing development is directly related to the geologic origin of the reservoir. This relation holds because the recovery of nonresidual mobile oil is controlled by vertical and lateral variations determined chiefly by depositional facies (*7, 8*) (Fig. 5). Variation, or heterogeneity, in reservoirs has long been recognized, and at certain scales is fairly well known; at other critical scales, it is poorly defined. Variations in ultimate hydrocarbon recovery from a reservoir result from three levels of heterogeneity (*9*).

1) Microscopic heterogeneities occur at the dimensions of pores within the rocks and include pore-size distribution, pore geometry, and amounts of isolated or dead-end pore space. These elements primarily affect the irreducible water saturation and the residual oil in swept portions of the reservoir. Consequently, analysis of microscopic heterogeneity is particularly important in design of tertiary recovery programs.

2) Macroscopic heterogeneity determines well-to-well recovery variability and is a product of primary stratification and internal permeability trends within reservoir units. Complexities include the following factors: (i) stratification (bedding) contrasts in grain size, texture, and degree of cementation; (ii) nonuniform distribution of stratification types; (iii) lateral discontinuity of individual strata; (iv) reservoir compartmentalization due to low-permeability zones; and (v) vertical or lateral permeability trends.

All these features are inherent attributes of the reservoir that are products of its depositional history and subsequent diagenetic overprint. It is at the scale of such macroscopic variability that large volumes of the reservoir are partially or wholly isolated from the effective swept area; this macroscopic heterogeneity controls the recovery of mobile oil.

3) Megascopic variations, such as regional facies changes, lateral variations in porosity, and separation of reservoirs by widespread sealing beds, reflect fieldwide or regional variations in reservoirs and are caused by either original depositional setting or subsequent structural deformation and modification. Such large-scale variations are conventionally evaluated during modern reservoir development and management by techniques such as structure, porosity, and reservoir mapping, and detailed well-log cross-section correlation.

Although macroscopic heterogeneity appears to be the critical determinant in the recovery of mobile oil, it is the scale of heterogeneity that is the least studied, the least known, and the most difficult of the three kinds of variations to define with precision and predictability. Thus it is almost never reflected in the deployment of conventional recovery techniques. Uniform well spacing in the development of reservoirs captures such heterogeneity only to the extent that a given well spacing subsumes it. The convention of essentially uniformly spaced intervals of vertical completion wells likewise fails to capture vertical, macroscopic heterogeneity. Further, the conventional process of reservoir simulation calls for grid

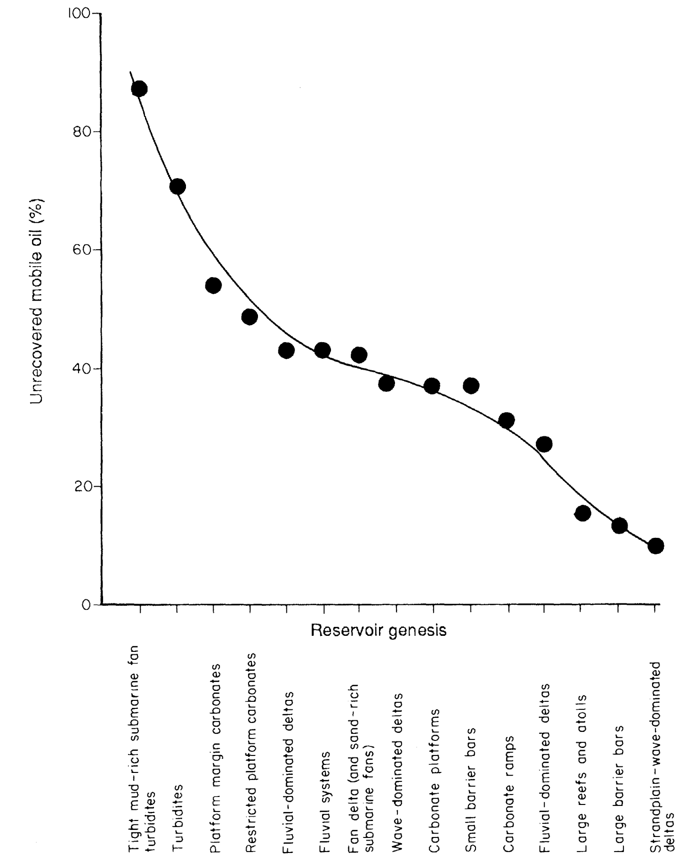

Fig. 5. Unrecovered mobile oil as a function of reservoir genesis and associated macroscopic heterogeneity. Based on sample of 450 largest reservoirs in Texas. [Adapted from (*8*)]

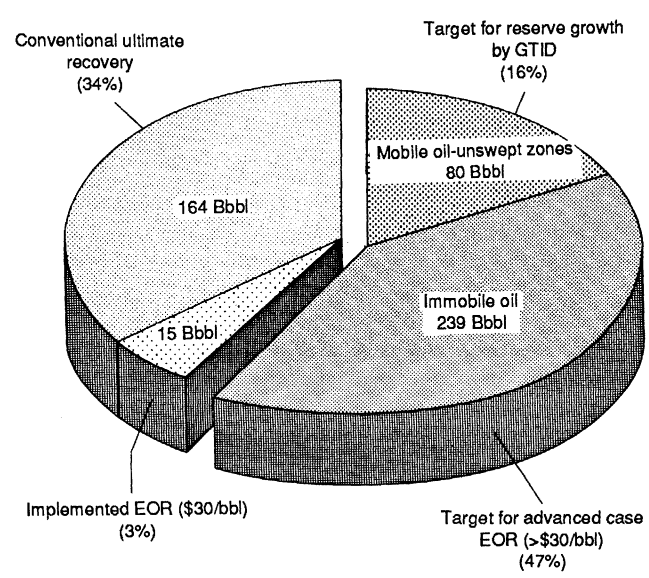

Fig. 6. Potential oil from reserve growth, showing percentage of 498 Bbbl of original oil in place (total U.S. resource). Distribution of oil in existing reservoirs, as targets for geologically targeted infill drilling (GTID) and enhanced oil recovery (EOR). [Modified from (*11*)]

cells that sum wellbore, generally microscopic heterogeneities, such as permeability and porosity, and extend these to large sections of the reservoir; the macroscopic fabric determined by stratigraphic variations is not captured.

The volume of mobile oil that exists in reservoirs but that will not be extracted with current levels of development is calculated in Texas to be about 35 Bbbl (*10*) and in the lower 48 states about 80 Bbbl (*11*). Three points relating to this calculation are as follows. First, large volumes of mobile oil remain to be recovered in existing, chiefly older, larger reservoirs. Second, mobile oil recovery is primarily a function of the extent of macroscopic-scale geologic variations within reservoirs. Third, extraction of unrecovered mobile oil requires only conventional technology. A significant portion of the remaining mobile oil could be recovered by systematically drilling reservoirs on an ever-closer well spacing and by completing wells at ever-smaller intervals. But such an approach would require the drilling and completing of a very large number of wells, perhaps more than could be justified economically. Thus, a major goal—the scientific thrust in additional recovery of the large volumes of mobile oil—is the understanding of macroscopic-scale, or stratigraphic, heterogeneity that will allow conventional drilling and completion technology to be used in a most effective, targeted fashion.

Although the volume of mobile oil is large and the technical basis for its recovery can be put into place, a fundamental question is, How much will actually be recovered? The results of increased field drilling, either by infilling or by extension, over the past few years provide insight. Of the 6 Bbbl of reserves added in Texas from 1973 through 1983, 73% came from infill and extension drilling in fields discovered before 1972 and in many discovered 50 years ago. For the period from 1979 through 1985 the contribution of infilling and extension drilling to total additions in Texas increased to nearly 80%. Nationally, from 1979 through 1984, 70% of total additions (*11*) came from infill and extension drilling, and, if the offshore is excluded from national figures, the percentages are essentially the same as those for Texas. National additions to reserves since 1979 from extended conventional field development have amounted to about 2 Bbbl annually. These additions along with those from new-field and new-pool discovery were sufficient to stabilize oil production in the lower 48 states. If only half of the estimated volume of mobile oil is eventually recovered, such volumes would be sufficient to sustain levels of additions and production achieved in the period from 1979 through 1985 for 20 to 25 years.

In addition to the mobile oil in existing reservoirs, the remaining residual oil amounts to one-quarter of a trillion barrels. Recovery of portions of this volume requires techniques that alter either the character of the reservoir or the physical state of the fluid. In either case recovery is more expensive than mobile oil recovery. To date, except for the thermal recovery of heavy oil, largely in California, tertiary recovery, or enhanced oil recovery, has contributed relatively small increments to reserve additions. Substantial increases in residual oil recovery or enhanced oil recovery require sufficient understanding of microscopic-scale heterogeneity to make the residual oil mobile as well as an understanding of macroscopic variations to recover the oil once it is rendered mobile in the reservoir. It thus has a double restraint. However, if one-fourth of the remaining known residual and heavy oil is eventually recovered, that volume would be sufficient to support current levels of U.S. domestic production for 20 years.

The remaining resource of oil in the United States is substantial. Exploration of new fields at current rates of finding can be pursued at the levels of the past few years for at least 30 more years. Reserve growth from conventional but geologically targeted development techniques can maintain recent production-stabilizing levels of additions for 25 years, with half the remaining volumes recovered. And advanced tertiary techniques, if pursued to the extent that one-fourth of remaining residual and heavy oil volumes could be recovered, would support 1985 levels of production of the lower 48 states for an additional 20 years (Fig. 6). In all, the U.S. oil resource base seems capable of providing stable production in the lower 48 states for the next 50 years.

Conclusion

As large as the remaining U.S. oil resource is, most of it can be converted to producible reserves only in relatively small increments. It is thus marginal relative to large unit-volume, low-cost production elsewhere, especially in the Middle East. The substantial volume of unrecovered mobile oil in existing reservoirs constitutes a major, moderate-cost resource. Discovery of new, small fields would be at a higher cost, but the stability in rate of finding means that ever-increasing prices are not necessary to support exploration. Further, the character of the remaining resource makes it particularly amenable to cost-reducing efficiencies available through targeted research and development. However, the resource cannot be developed at current prices to the extent that stable U.S. production levels of the first half of this decade can be maintained.

A central policy question emerges. Is the ample though marginal resource base of the United States worth pursuing at an intensity sufficient to maintain stable levels of domestic production? The productive character of the U.S. oil and gas resource base focuses this policy question sharply. Just as the resource base was responsive to aggressive drilling stimulated by higher prices of the past decade, it is now responding to the greatly diminished drilling effort brought on by the collapse of oil prices in the beginning of 1986 that was induced by the Organization of Petroleum-Exporting Countries (OPEC). Statistics show that year-long loss of production capacity in 1986 amounted to 682,000 barrels a day (*12*). If adjustments are made, for an actual increase in Alaska production during 1986 and for the fact that federal offshore production remained level, the on land oil provinces of the lower 48 states lost 725,000 barrels a day of productive capacity, a year-long decline of 12%. In fact, most of the loss was sustained in the last three-quarters of the year (*13*). This loss of capacity was concentrated in areas holding the most marginal parts of the resource base, where additions depend on small increment discovery and development and where stripper well (10 barrels a day or less) production predominates. As an example, Oklahoma sustained a year-long decline in production wells in excess of 20%. Only in areas where larger scale reserve growth had been achieved in recent years, for example, infill drilling in the Permian Basin of West Texas and thermal recovery in California, was the production impact moderated, and even in these areas year-long decline approached 10%.

The production capacity of oil in the United States from about the 1930s through 1950s, when production was sustained during periods of diminished drilling, rested chiefly on high output, large fields. Today, productive capacity depends chiefly on a resource base, which recent experience indicates will yield supplies rather directly related to immediate levels of drilling. If, as a matter of national policy, relatively stable levels of domestic production are desirable or necessary, the remaining resource base can provide these levels if aggressive drilling practices are used. In recent years such aggressive resource development here and elsewhere coupled with diminished oil demand, both brought on by OPEC-supported higher prices, created substantial excess production capacity in the world and a severely reduced market share for OPEC. The current low prices, resulting from increased production by OPEC, are diminishing and will continue to diminish marginal resource development in the United States and will again lead to large levels of oil imports. The U.S. resource base is capable of precluding such imports, but in the face of deliberate attempts to diminish it, that capability will be largely foregone unless, in the national interest, appropriate support is provided.

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A Visit to Chernobyl

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Details of the accident at the Chernobyl nuclear power plant were given by Soviet experts at a special International Atomic Energy Agency meeting in Vienna, Austria, in August 1986. Several unanswered questions were made much clearer by a visit to the decontaminated and operating power plant at Chernobyl and by discussions with Soviet scientists. The visit gives us insights into the way the Soviets design their technology, the consequences of the accident, and the magnificent way they coped with the disaster. Although there are general conclusions to be drawn for the rest of the world, such as the realization that operators of technological systems can and will deliberately cut out safety systems, the primary specific conclusion is to be grateful that the West did not follow the Soviet route in its development of nuclear power.

IN FEBRUARY 1987, I WAS PRIVILEGED TO VISIT THE V. I. Lenin power plant near Chernobyl in the Ukraine. I carried my own camera and Geiger counter. Immediately after the accident in April 1986, I studied in detail the Russian papers and reports of the accident. I went to the "Post Accident Review Meeting" in Vienna, Austria, in August 1986, where the Soviets described in detail the reactor, the accident, the consequences, and the cleanup in progress at that time (*1*). But at Vienna there were many unanswered questions.

During and before my visit, I also had the opportunity to ask questions of those persons responsible for the following aspects of the accident: advising on the evacuation (Academician L. Ilyin); the prompt medical care (Dr. A. Guskova); the reactor design (Academician Belyaev, Dr. Bulakov, Dr. Kusmin, and Dr. Prazenko of the Kurchatov Institute); the measurement of radioactivity release (Dr. V. F. Demin); the measurements of radioactivity in the environment (Professor Pavlowski of the Institute of Medical Physics); radioactivity in the nearby river (Dr. Khitrov of the Vernatsky Institute of Geophysics and Analytical Chemistry); Dr. Petrosyants, chairman of the State Committee of Atomic Energy; Academician Abagyan, director of the newly formed institute for research into the operation of nuclear power plants; Minister of Atomic Energy, Dr. N. F. Lukonin; Soviet leader Mikhail Gorbachev's adviser, Academician E. P. Velikhov; and many other scientists and individuals. Because of the compartmentalization of Soviet society, no one person could answer all my questions; indeed, there were disagreements about details. By talking to those persons directly responsible, a much clearer picture of the accident, its causes, and the Soviet response to it now emerges.

The Accident

As is well known, at 0123:48 on Saturday, 26 April, unit 4 of the four-reactor complex blew up as the core suffered a prompt critical excursion. The steam pressure as the reactor went to between 100 and 500 times full power (*2*) lifted a 1000-ton cover plate, turned it on its side (*3*), and ripped open the reactor, leaving the hot core exposed to the environment.

In the initial burst, a large amount of radioactive material was released, and more was released over the next 10 days. Dr. Demin estimated (*4*), on the basis of ground deposition and airplane measurements of activity in the plume, that about 3% of the heavy elements of the core were thrown out onto surrounding buildings and the countryside, as were about 13% of the more volatile cesium and 20% of the iodine. Western reports (*5*) suggest that the amount of iodine released was considerably greater than this estimate, probably about 50%. On the basis of the winds measured by satellite and the large initial rise of the radioactive plume, they estimate that much of the radioactivity in the initial burst went high over the countryside of Belorussia to be deposited in Europe, and that the Soviet estimates inadequately account for this. I discussed this issue with Dr. Demin, and although he believes that his estimates are correct within the stated 50% uncertainty, it is clear that the Soviets know less than we do about the initial burst and its composition. In order to deduce the amount released in the initial burst from the

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