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National Energy Resource Issues

Geologic Perspective and the Role of Geologic Information

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U.S. GEOLOGICAL SURVEY BULLETIN 1850

ABBREVIATIONS

BBO	billion barrels of oil
Btu	British thermal unit (heat measurement)
EOR	enhanced oil recovery
MMS	Minerals Management Service
NCRDS	National Coal Resources Data System
NSPS	new-source performance standards
NURE	National Uranium Resource Evaluation
OPEC	Organization of Petroleum Exporting Countries
Quad	quadrillion Btu
RNSPS	revised new-source performance standards
R/P	reserve-to-production ratio
TCFG	trillions of cubic feet of gas
USGS	U.S. Geological Survey

On the Cover: Rocks of the energy-resource-rich Mesaverde Group of Cretaceous age. Cliff-forming Point Lookout Sandstone is highlighted against a storm approaching over the Four Corners region of the Colorado Plateau. (Photograph by Christine Turner-Peterson, U.S. Geological Survey.)

National Energy Resource Issues

Geologic Perspective and the Role of Geologic Information

By U.S. GEOLOGICAL SURVEY

U.S. GEOLOGICAL SURVEY BULLETIN 1850

DEPARTMENT OF THE INTERIOR
DONALD PAUL HODEL, Secretary

U.S. GEOLOGICAL SURVEY
Dallas L. Peck, Director



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National Energy Resource Issues: Geologic Perspective and the Role of Geologic Information

By U.S. Geological Survey

EXECUTIVE BACKGROUND AND OVERVIEW

Energy resources are a fundamental part of the economic strength and stability of the United States, and the key resource in today's industrial economy is oil. Although several geopolitical and economic factors have combined recently to reduce energy prices from their former high levels, the world petroleum market for the foreseeable future appears likely to be volatile with regard to both price and supply. Furthermore, the United States is again growing increasingly dependent on imported oil and will be strongly affected by swings in the world market.

Two-thirds of the energy currently consumed by the United States is provided by oil and gas (fig. 1); more than one-third of the oil is imported (DeGolyer and MacNaughton, 1986, p. 51). Resource analysts predict that domestic oil and gas production will continue to decline irreversibly from peak production in the 1970's. Since the first quarter of 1986, this decline, driven by falling oil prices and the consequent retrenchment of the American oil industry, has been quite sharp. Production from existing wells is declining, and stripper wells are being shut in and abandoned. New petroleum fields are more difficult and expensive to find, and exploration has been seriously curtailed. In addition, industry has either slowed or stopped research on enhanced oil recovery and the development of alternative higher cost energy resources such as oil shale and synthetic liquid fuels from coal. It seems inevitable that U.S. dependence on foreign supplies of oil will increase.

Long-term prospects for the future supply of oil are determined not only by political and economic factors but also by geologic realities. The United States is the most mature region in the world in terms of exploration for oil and cannot reasonably expect to increase oil production or even to maintain current levels of production for long.

Many of the so-called frontier areas in Alaska and along the Atlantic coast have proved either to be barren or to have much less petroleum than first expected. Development of other promising areas in Alaska and offshore California is delayed indefinitely because of conflicts with environmental restrictions and recreational land use plans.

As a result of the petroleum supply shocks of the 1970's, many policy planners recommended that the United States formulate coherent long-term energy strategies to ensure supply, modulate demand, and avoid future crises. A decade later, the world glut of low-priced petroleum is fostering the erroneous belief that the United States has successfully achieved national energy stability, and long-term strategies to ensure a continuing and reliable supply of petroleum have not been devised. Between the mid-1970's and the present, a combination of government policies and energy-commodity price changes has resulted in a small but significant shift from oil and gas to other fuels (fig. 1). Nevertheless, combined oil and gas use in the United States still is twice that of other energy sources.

Any supposition of energy stability based on today's relatively comfortable situation with regard to oil supply and price is undercut by an examination of the national and world oil resource picture. Discovery rates of crude oil, by region, for the past 60 years are compared in figure 2 with annual production amounts. Discovery rates have decreased from 37 billion barrels of oil (BBO) per year in the early 1960's to a present-day level of about 10 BBO per year. Production of about 20 BBO per year now outpaces discovery by a factor of two. A worldwide increase in industrial activity, and hence in energy consumption, would produce an even greater disparity between discovery and demand-driven production. A similar gap between discovery and production exists in the

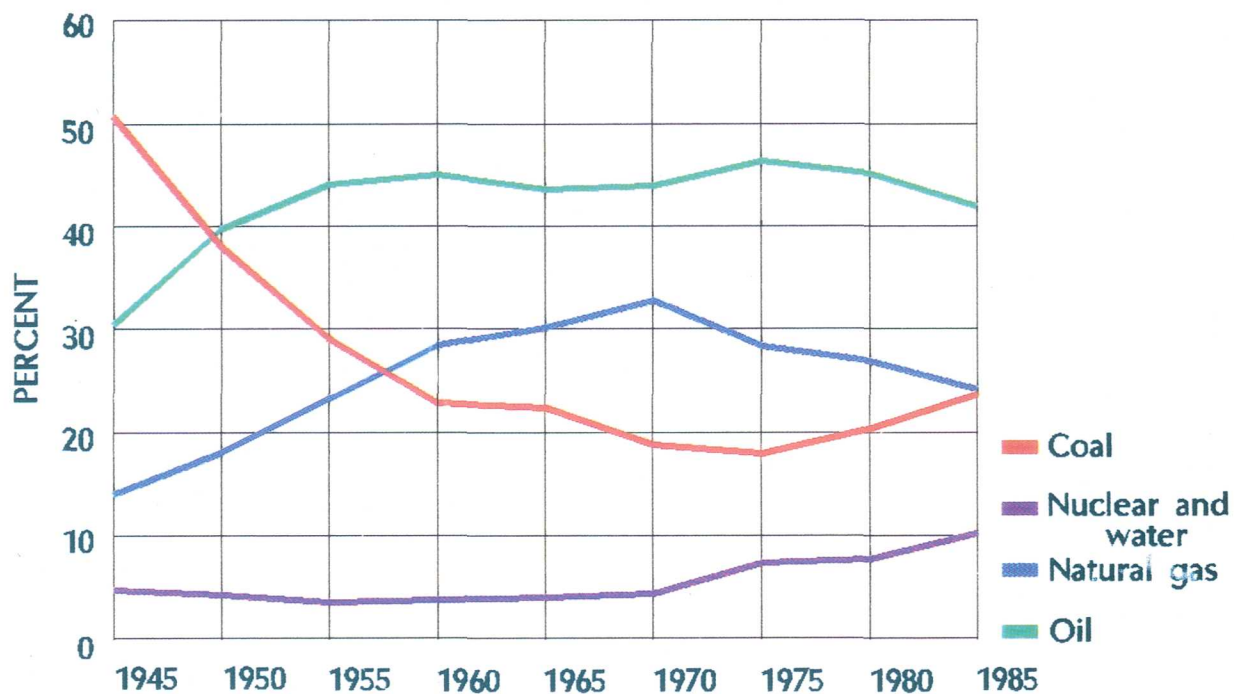


Figure 1. Sources of energy consumed in the United States, 1945–1985. Modified from DeGolyer and MacNaughton (1986, p. 107).

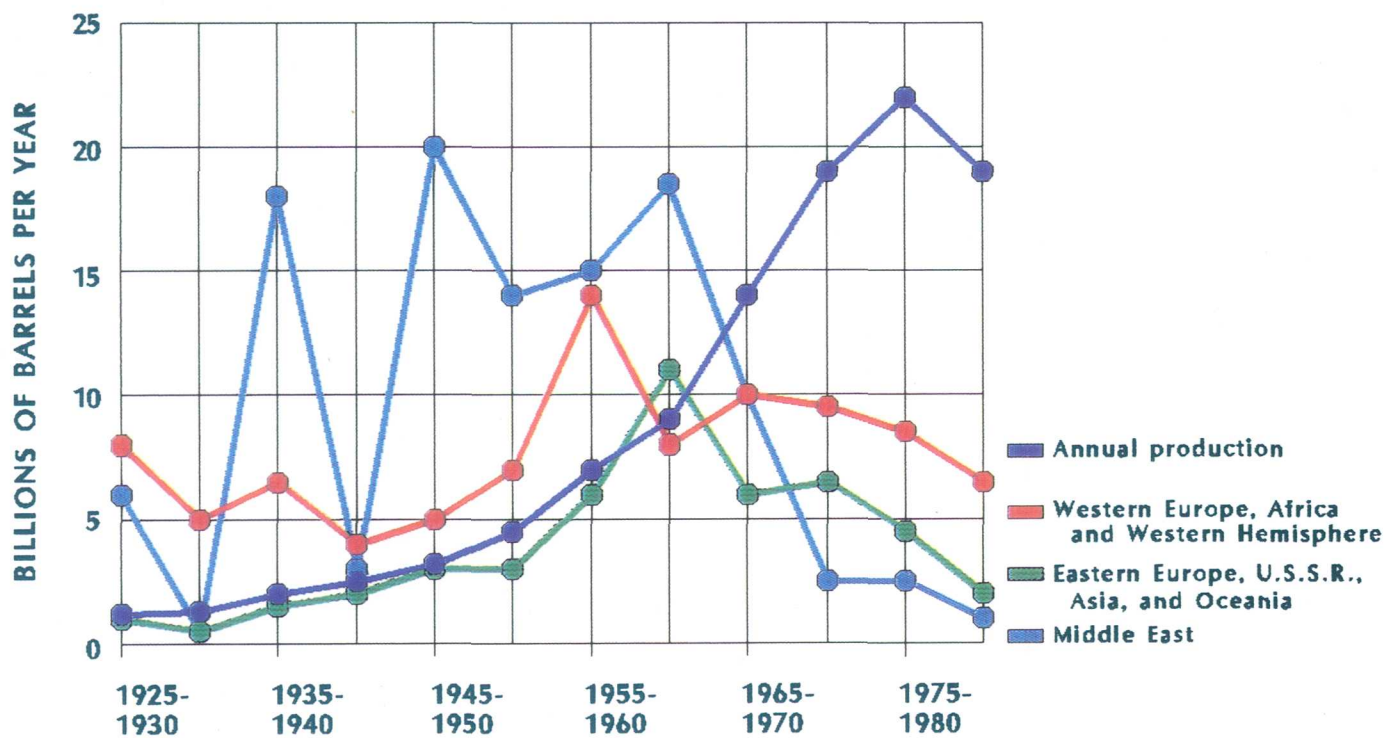


Figure 2. Discovery rate of crude oil by region, averaged over 5-year periods, and annual world production, 1925–1985. Modified from Masters and others (1987, fig. 5).

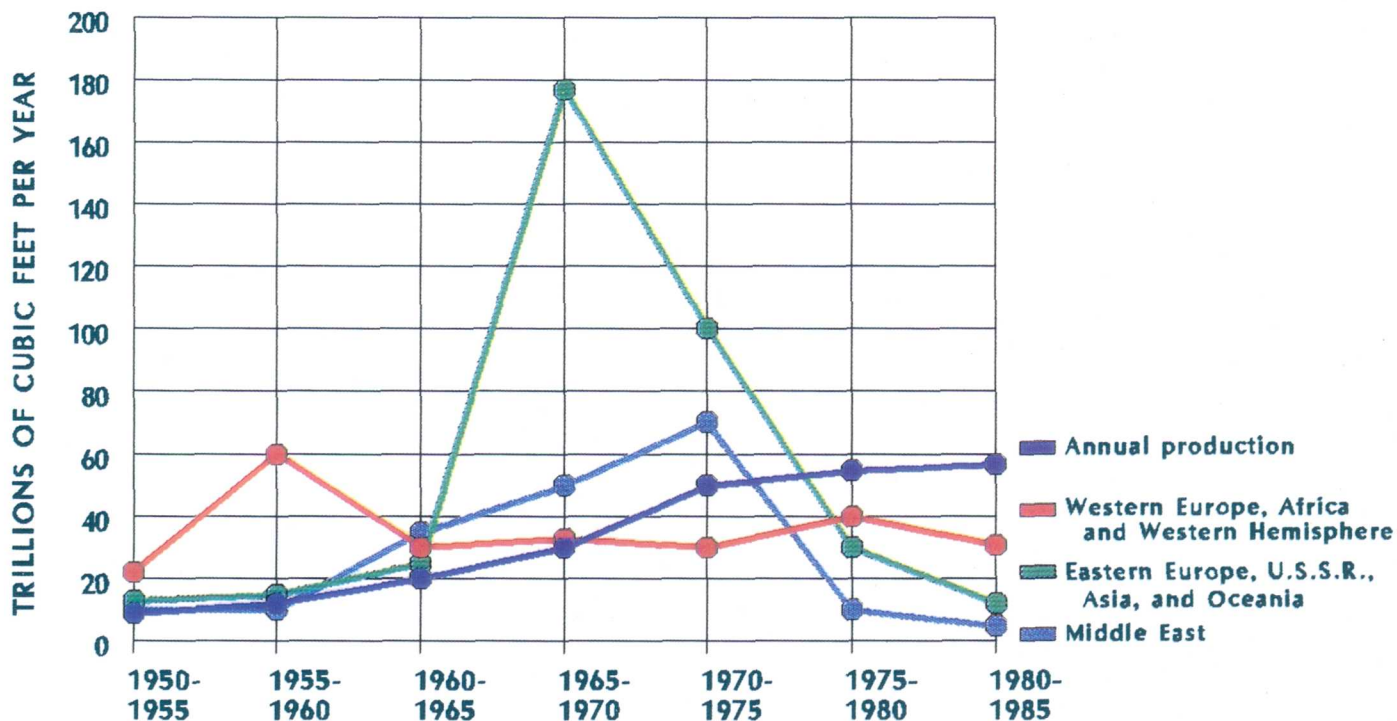


Figure 3. Discovery rate of natural gas by region, averaged over 5-year periods, and annual world production, 1950–1985. Modified from Masters and others (1987, fig. 7).

United States, despite enormous increases in drilling before the current downturn in activity.

Discovery and production data for natural gas are shown in figure 3. As the result of enormous gas discoveries in the Middle East and in the U.S.S.R. during the late 1960's and early 1970's, these areas now are known to have a major portion of the world's gas resources. For some years, worldwide gas production has outpaced reported discoveries but not yet to the extent seen for oil, perhaps because gas production is not economic in many areas. In the United States, annual consumption of gas currently is about twice the amount discovered annually.

Between 1975 and 1986, important changes were made in U.S. sources of oil. Most of our imported oil now comes from suppliers outside the Middle East. However, the disproportionate share of world oil reserves and undiscovered resources enjoyed by nations of the Organization of Petroleum Exporting Countries (OPEC) and the less rapid drawdown of these reserves assure OPEC producers of an increasingly dominant role in the conventional petroleum market in the not-too-distant future (figs. 4, 5). The difference between a future situation (predicted for the 1990's) and the situation in the 1970's is that, in the future, OPEC dominance is expected to be stable and long term.

To avoid future U.S. dependence on foreign oil supplies, domestic oil supplies must be found and developed, and alternative liquid-hydrocarbon supplies must be made competitive by advances in geology and technol-

ogy. Long-term commitments to these goals currently are difficult to maintain because of low prices and the temporary abundance of oil in the world market.

Oil is used primarily for transportation and in the petrochemical industry; nuclear power and hydropower cannot be substituted for these uses, and coal can be used only if it is converted to liquid form, an expensive and not yet commercially viable process. Thus, the principal problem in achieving national energy stability is the replacement of an increased proportion of liquid hydrocarbons as conventional oil becomes scarcer and more expensive or if international supply arrangements are disrupted.

Coal generally has been assumed to be the Nation's energy "ace in the hole" because of its abundance, but increasing U.S. reliance on coal will not be simply a matter of physical availability. Coal deposits in the United States are of widely varying qualities; each deposit poses a different set of challenges to economic extraction and use, and each has different environmental ramifications. In addition, much of the enormous U.S. coal resource base cannot be utilized because the overlying surface is either built upon or restricted by land use regulations. Much of the resource will never be economic to use because it is too thin, too deep, or too low in quality.

Alternative hydrocarbon resources such as oil shale, gas in tight reservoirs, and tar sands are abundant in the United States but pose their own sets of challenges to economic use. Rates of extraction for these alternative resources will be lower than those for conventional hydro-

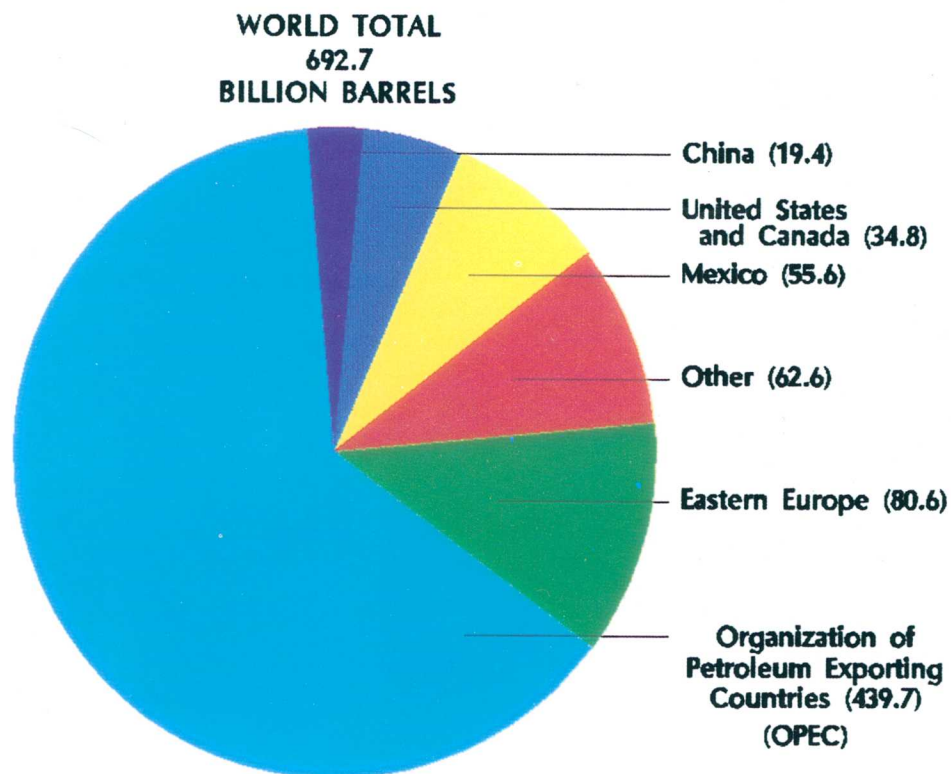


Figure 4. Estimated reserves of crude oil by major producing area, as of January 1, 1986. Modified from DeGolyer and MacNaughton (1986, p. 1).

carbons, and costs will be significantly higher. In addition, using these resources will involve environmental costs that must be factored into decisions about the economic feasibility of adding alternative resources to the national energy mix.

In considering an evolving national energy mix, it is important to understand that energy resources such as oil, gas, coal, and uranium are nonrenewable, and, as the more readily available deposits are depleted, the remaining resources will be more difficult to find and produce at a desirable price or with requisite quality. Moreover, meeting tomorrow's national energy needs by shifting from one energy source to another or by converting from today's energy resources to other less conventional energy resources not currently marketable will involve major technological and economic shifts. Such transitions require planning and lead time in order to avoid major disruptions in the Nation's economic fabric.

Meeting future U.S. energy needs requires major and timely decisions about resources and their use. Comprehensive, reliable geologic information is a requirement for informed decisions, whether at the level of national energy policy or at that of corporate exploration strategy. Although basic policy will be determined to a large extent by economics and politics, geologic information is a necessary component in evaluating alternative paths to

national energy security and industrial success. Information on the geologic setting and character of reservoir rocks and resource materials is important, whether the aim is more effective exploration, improved recovery of conventional oil and gas, better technological approaches to the extraction and use of unconventional hydrocarbons, or solution of problems inherent in increased coal utilization.

The oil reserves of the United States are only about nine times annual domestic production (DeGolyer and MacNaughton, 1986, p. 1). To increase this ratio, emphasis should be placed on improved exploration efforts, in particular the exploration of frontier areas that have reasonable prospects of containing large oil fields. Such exploration efforts require improved knowledge of the regional geologic setting and history of the various exploration areas. In some frontier areas, especially those in relatively deep water parts of the continental margins, acquisition of the requisite geologic information has only just begun.

Another critical approach to making the short-term and midterm energy situation of the United States more favorable, at relatively low cost, is the improvement of conventional and enhanced oil recovery techniques. Improved recovery methods will increase the amount of usable conventional oil that can be recovered from reser-

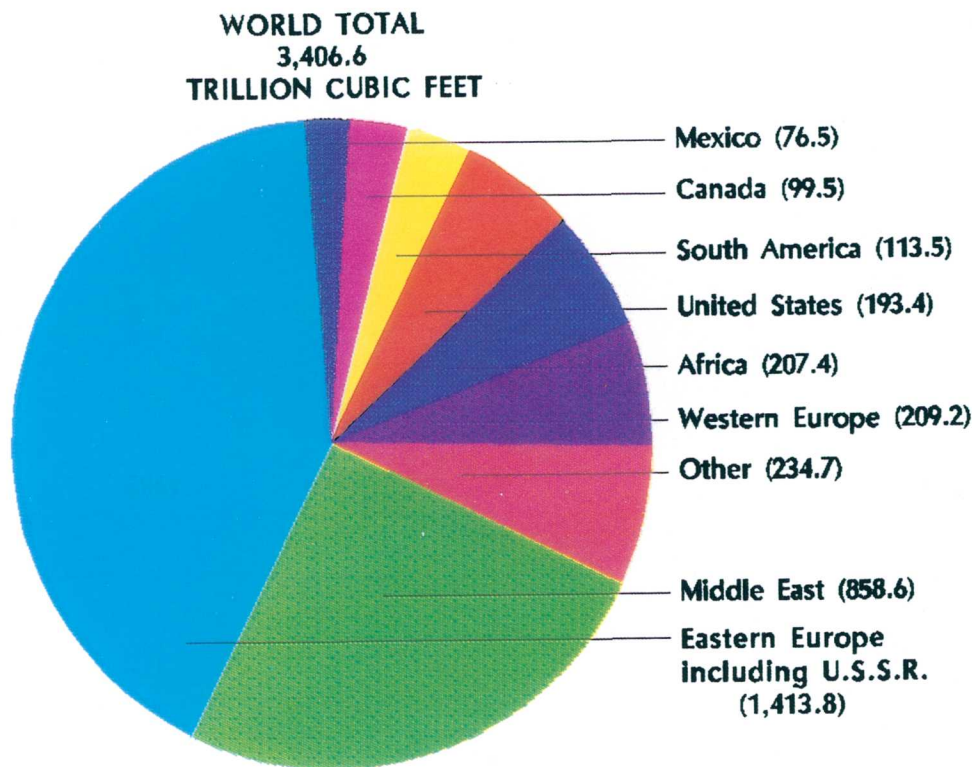


Figure 5. Estimated reserves of gas by major producing area, as of January 1, 1986. Modified from DeGolyer and MacNaughton (1986, p. 14).

voirs already in production, although at lower recovery rates and higher costs. Better information as to the geologic character, setting, and history of the reservoir rocks will be necessary to accomplish these advances.

Geologic information also must underlie any planning for a major increase in coal use. The nature of U.S. reserves must be defined, especially variations in quality and accessibility, and the reserves need to be categorized according to their different potentials for a variety of extraction techniques and processing requirements and their suitability for different ultimate uses. Development of economical new technologies for coal cleaning, combustion, and flue gas treatment and waste disposal or for coal liquefaction and gasification requires detailed geologic information on the coals to be handled.

Other strategies to reduce reliance on conventional petroleum resources involve utilization of oil shale, tar sand, gas in tight reservoirs, gas hydrates, and coal-bed methane. These resources usually are referred to as "unconventional" or "alternative" because they generally require more technology or engineering advances, will cost more to tap, will yield their hydrocarbons at relatively slow rates, and, as a result, will ensure higher costs of the ultimate product. Attempts to obtain energy from these sources must be based on an understanding of the host rock, including a detailed knowledge of its geologic setting

and composition and the geologic processes that have affected it and its contained hydrocarbons. In addition, these potential resources must be accurately surveyed and assessed in regard to location, quantity, and quality.

Systematic studies of the physical character, mineralogy, and chemistry of resource-bearing rocks are required in order to understand the limits and possibilities of all potential oil and gas resources and the most effective approaches to their use. Assessments of resource quantity alone are no longer sufficient for the informed determination of either national policy or corporate strategies. It is necessary to determine what is accessible and its quality and whether current exploration and exploitation techniques are adequate to produce new energy supplies at reasonable cost. Such resource characterizations will help build a solid foundation of information from which to view the energy future of the United States.

This report offers a perspective on U.S. energy resources from the point of view of the geologic realities that control or constrain their large-scale use now and in the future. A national context is provided for each major component of the national energy mix, and some of the more evident problems are discussed. The role of geologic information in helping to solve these problems is emphasized. Examples throughout the report illustrate how

basic and applied geologic research is producing information to support present and future energy resource directions. The examples are drawn principally from U.S. Geological Survey (USGS) work, some of it done in cooperation with State or other Federal agencies. Although research on energy matters is also being done in universities and in other Federal and State agencies, USGS research is focused particularly on the geology of energy resources, which is the fundamental factor in finding and using any resource and is the theme of this report.

Many people contributed to the production of this volume. Terry W. Offield, Susan Garbini, and Stanley P. Schweinfurth gathered material and wrote sections of the report. Thomas D. Fouch, Oswald W. Girard, Harold J. Gluskoter, and Kathie R. Fraser reviewed the report in its entirety. David H. Root, Charles D. Masters, Emil D. Attanasi, L.J.P. Muffler, and M.D. Carter reviewed various sections and also contributed material. Judith W. Stoeser edited and produced the volume. Nancy K. Gardner translated the illustrations to computer graphics. Gary W. Hill provided essential technical advice.

PETROLEUM RESOURCES

Foreign supplies of crude oil were virtually irrelevant to the United States between 1860 and 1950, by which time we had produced 39 BBO and the rest of the world only 23 BBO (fig. 6A). During that period, domestic demand was satisfied by domestic production. From 1945 to 1970, oil production in the United States increased at a slow and steady rate, whereas production in the rest of the world increased at a much faster rate (fig. 6B). As world industrial and transportation needs have grown, world demand for oil has risen steadily, and, at the same time, the United States has become a major importer of petroleum.

Demand for oil has driven production, and, from 1971 until recently, a seller's market existed on the world scene. Both the creation of the seller's market and its recent collapse were controlled by policies of OPEC or its individual member nations rather than by the United States, and this shift in control further indicates our changed role in this arena. Numerous buyers compete in the world market to purchase oil, and the United States has no special position in obtaining the large amounts of oil that it imports each year. Competition among buyers will intensify as world demand continues to increase.

For many years to come, petroleum will dominate the pattern of world energy use as the most convenient and versatile energy resource. The price and availability of oil will affect the stability and pricing of almost all sectors of the world energy economy. It is hard to overstate the importance of accurate world petroleum resource assessments and of improved geologic information, both of which will enable the United States to foresee future requirements for foreign oil and to improve the domestic supply of oil and gas.

GLOBAL SETTING

Most of the world's crude oil resources have been discovered, and future discoveries are unlikely to match past discoveries. The total crude oil resource comprises three components: cumulative production, remaining known reserves, and undiscovered recoverable oil. Estimates of world total cumulative crude oil production, reserves, and undiscovered resources by the USGS (Masters and others, 1987) have changed significantly since they were last made. Between January 1981 and January 1985, cumulative production of crude oil increased from 445 to 524 BBO, estimates of reserves increased from 723 to 795 BBO, and estimates of undiscovered resources decreased. The 95-percent likelihood estimate of undiscovered resources decreased from 321 to 262 BBO, the 5-percent likelihood changed even more dramatically

from 1,417 to 927 BBO, and the most likely value, or mode, decreased from 550 to 425 BBO. Changes in estimates of undiscovered resources reflect (1) the transfer, following discovery, of undiscovered resources into reserves and production; (2) new geologic insights into petroleum occurrence and improved information on the petroleum geology of the U.S.S.R. and Mexico, both of which indicate more limitations on resource potential than previously assumed; and (3) major disappointments in the exploration of areas in the United States previously regarded as highly promising frontiers.

New estimates of the ultimate amount of conventional crude oil that will be produced in the world by region suggest that the distribution of undiscovered resources is similar to that of discovered resources (Masters and others, 1987) (fig. 7A). If these estimates are reasonable, then the distribution pattern of petroleum resources in the world is established and can be used as a basis for long-term national planning. It is expected that future discoveries will be concentrated in known productive areas and that the best discoveries in those areas have already been made. Exploration surprises, both favorable and unfavorable, certainly will occur but most likely will not materially alter the global resource picture.

Not only do OPEC producers hold the bulk of the world's future oil supply (fig. 8A), but they also currently are drawing down their resources proportionately less rapidly than are other areas of the world. This situation is illustrated in figure 9, in which the reserve-to-production (R/P) ratio of the United States can be contrasted with the much larger R/P ratios of many other producing nations. The larger the ratio, the longer a nation can continue at its current rate of production. The United States currently has proved reserves equal to 9 years of production at today's rate, whereas Saudi Arabia has reserves equal to 141 years of production. The inescapable conclusion is that, in the future, OPEC producers will be able to exercise increasing control over the amount and therefore the price of world petroleum supplies.

As a result of limited market interest, the world's gas resources are less known and less developed than are its crude oil resources, but the geographic distribution and the abundance of gas resources appear to be about the same as those of oil resources (fig. 8B). A partial exception to this linked distribution pattern is the U.S.S.R., whose gas resources are much larger than its oil resources and larger than the gas resources of the Middle East. The large resources of gas in the Middle East, which have been located in the course of oil exploration, have not been developed at a significant rate because of the absence

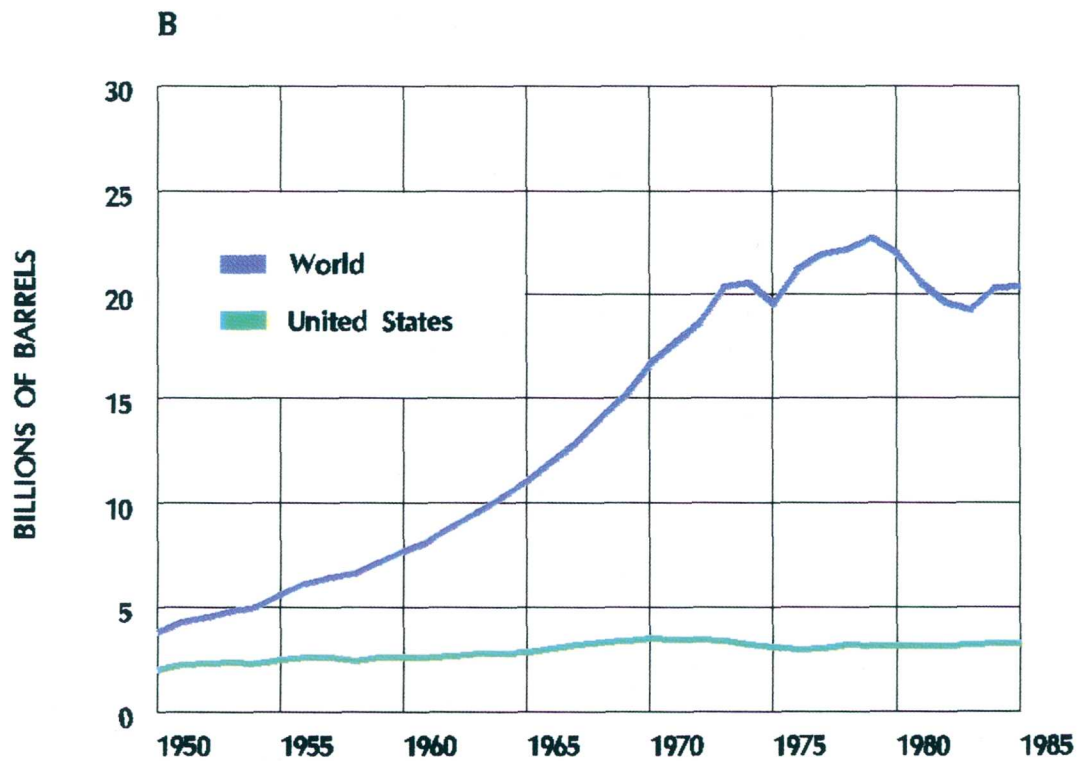
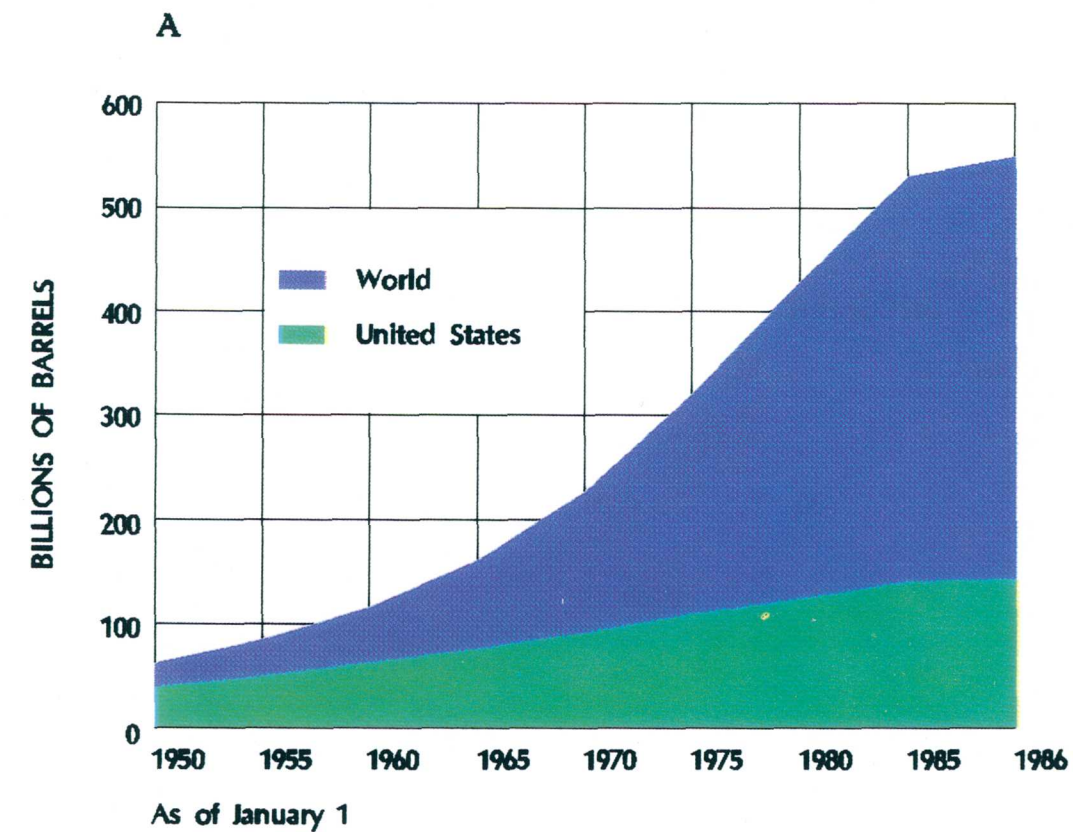


Figure 6. Cumulative (A) and annual (B) U.S. and world production of crude oil. Modified from DeGolyer and MacNaughton (1986, p. 4, 5, 12).

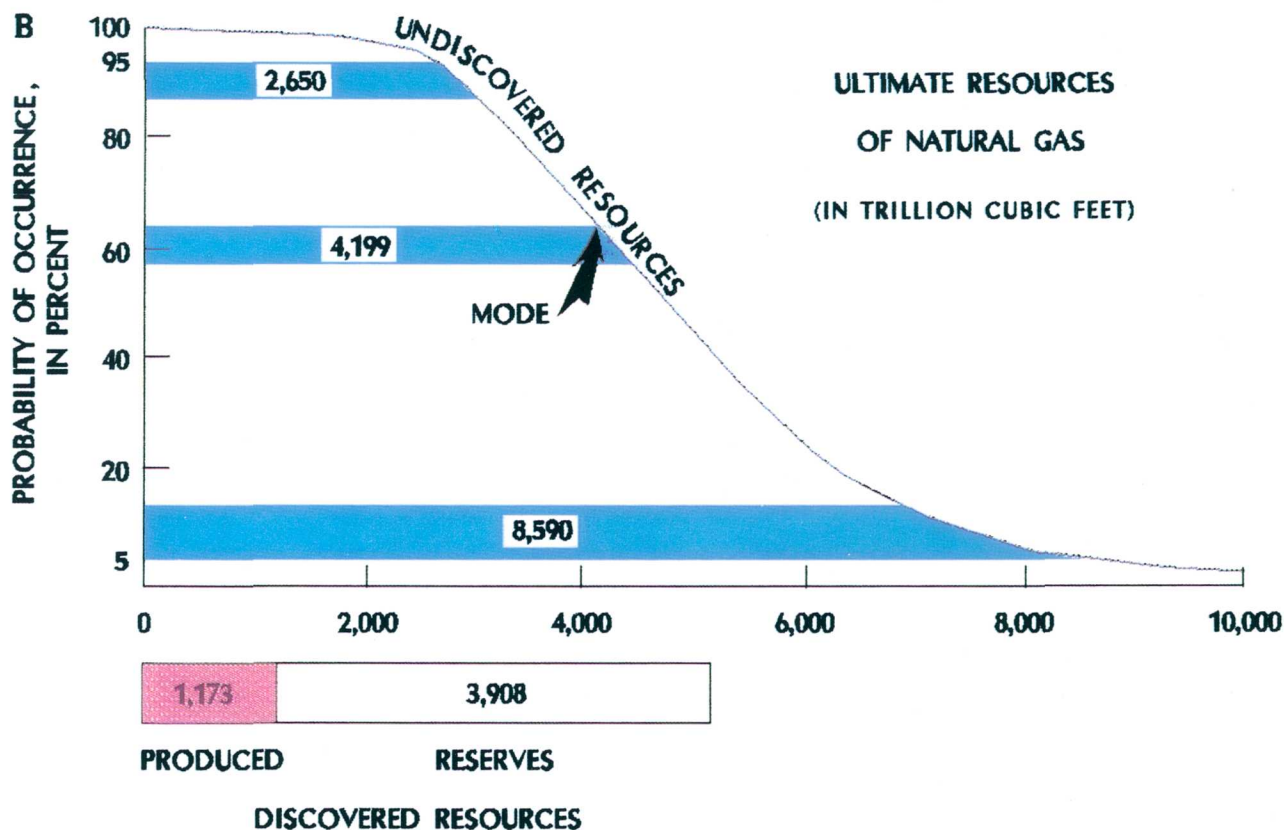
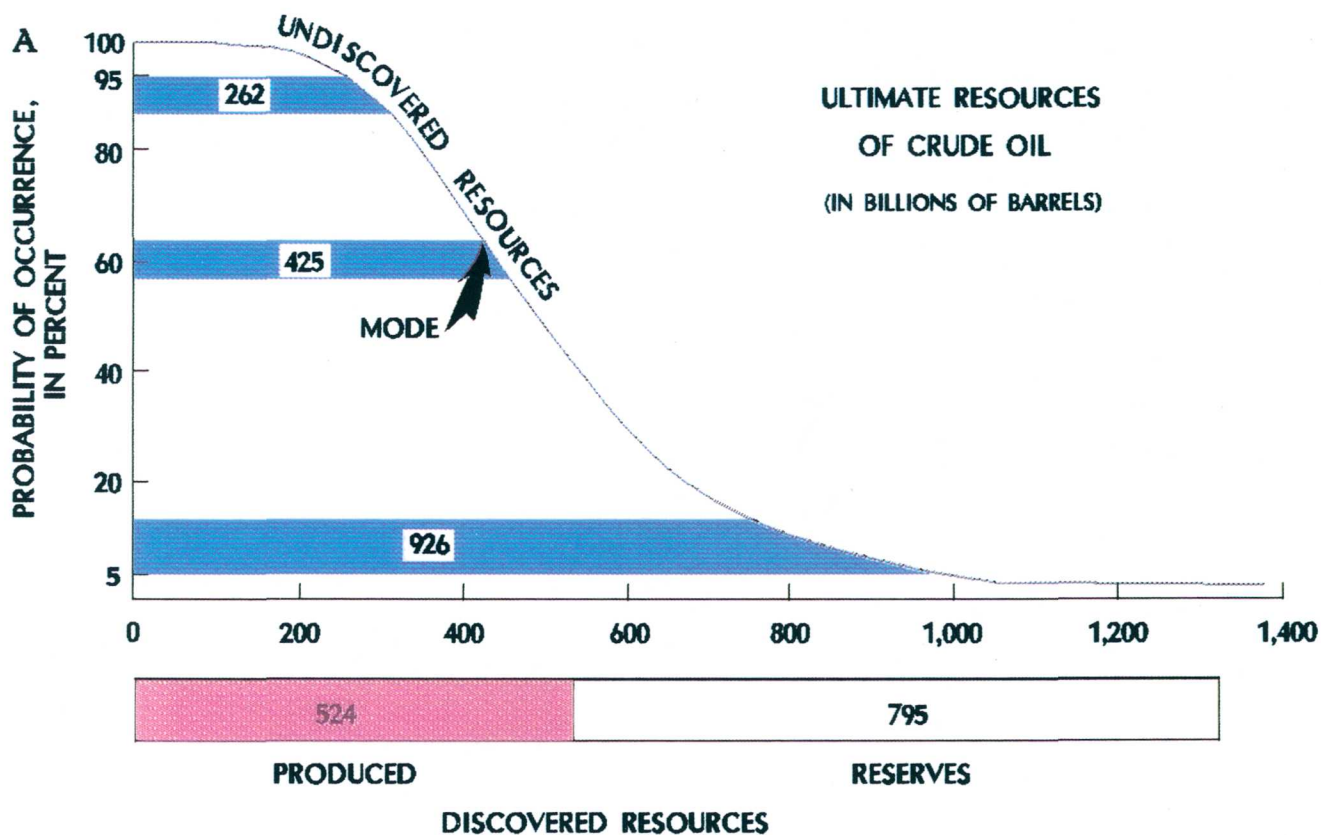


Figure 7. Total world resources of crude oil (A) and gas (B), including discovered resources (cumulative production and reserves, as of January 1981) and undiscovered resources (as of January 1983). Modified from C.D. Masters, E.D. Attanasi, W.D. Dietzman, R.F. Meyer, R.W. Mitchell, and D.H. Root (written communication, 1987).

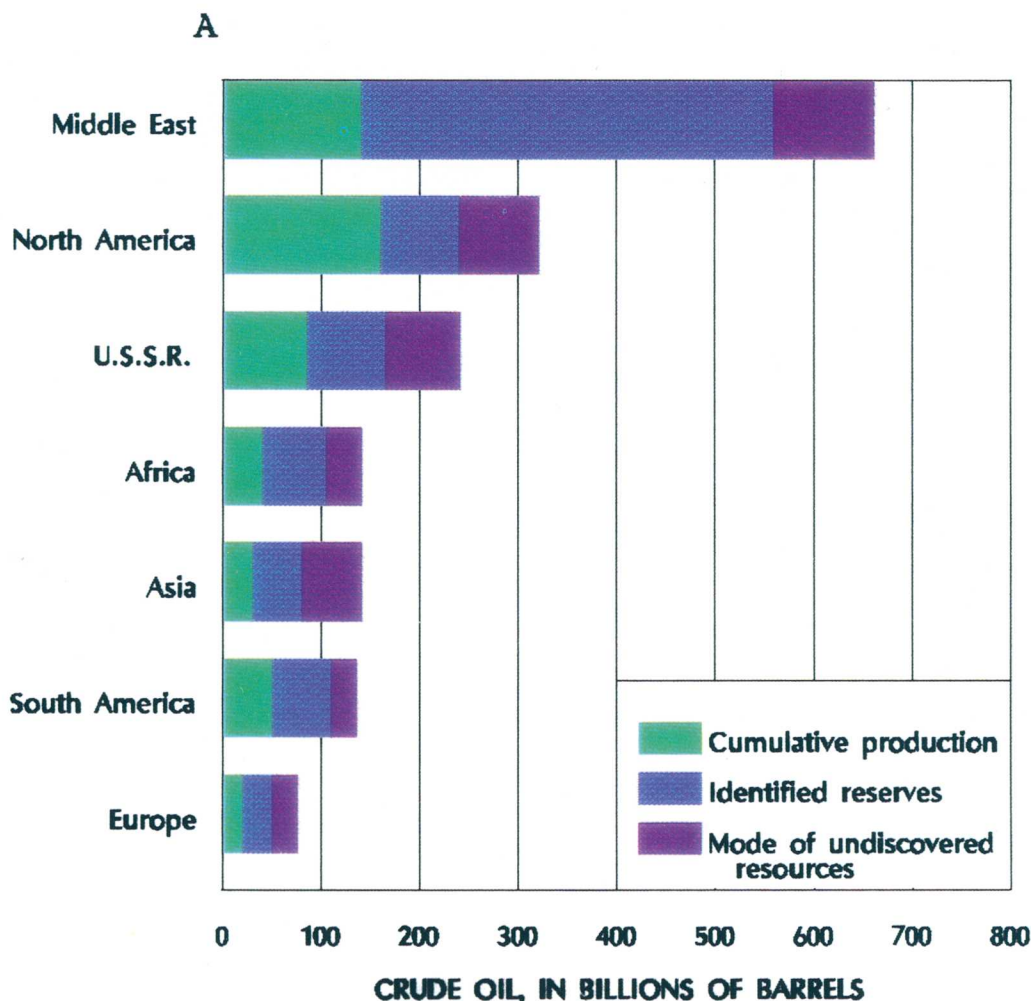


Figure 8. Regional distribution of world resources of crude oil (A) and gas (B), as of January 1, 1985. Modified from Masters and others (1987, figs. 3, 4).

of a local market. In the future, Middle Eastern producers probably will be able to export gas (liquid natural gas) from the same dominant position that they have held in oil.

Available evidence suggests that, during the next 20 years, non-OPEC production capacity of crude oil will decline relative to OPEC capacity. The United States and the U.S.S.R. produce more than 38 percent of total world crude oil and are the principal non-OPEC oil producers (DeGolyer and MacNaughton, 1986, p. 3). Despite advances in exploration and production technologies, neither country is likely to increase production in the future. Many small, non-OPEC producing countries have increased production during the past decade; production in many countries will peak during the next decade and then slowly decline (National Petroleum Council, 1987, p. 165). A few countries, such as Norway, Egypt, Colombia, Brazil, and Ecuador, are reporting significant new discoveries and may be able to maintain or increase production

capability; however, these increases will not change the basic world outlook for oil.

Although no one can truly predict the extent of resources not yet tested by drilling, geologic evidence from around the world suggests that most future discoveries will be found in only a few regions, regions that for the most part have already experienced some exploration. New giant discoveries, so disproportionately important in terms of resource distribution, probably will be concentrated in just a few basins within these regions. This scenario is probable because a large occurrence of any natural resource requires that a number of independent

Figure 9. Surplus production capacity is indicated by a decline in the production curve through time; full capacity is indicated by a steady increase or leveling off of the production curve. R/P is reserve-to-production ratio, determined by using estimated reserves as of January 1, 1986 (in parentheses) and production for 1985 (daily production times 365). Data from DeGolyer and MacNaughton (1986). ►

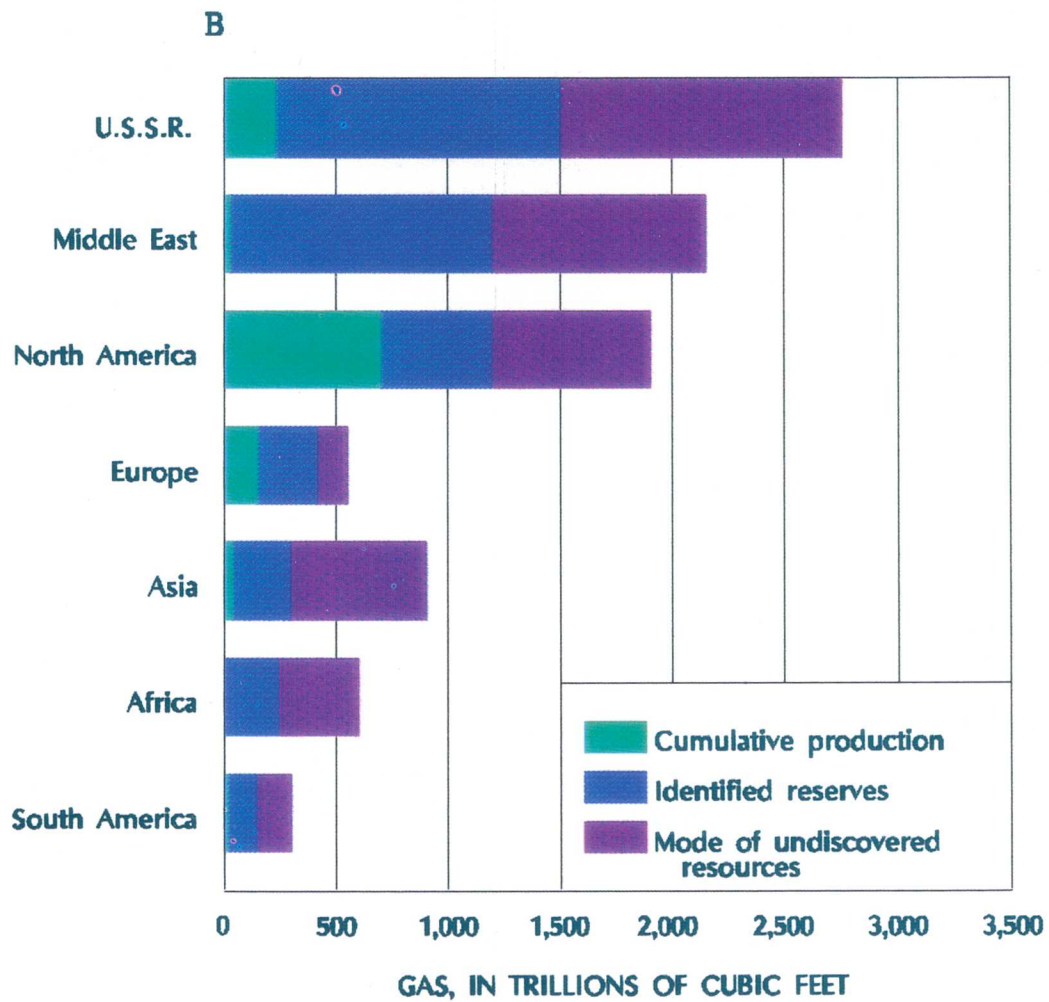
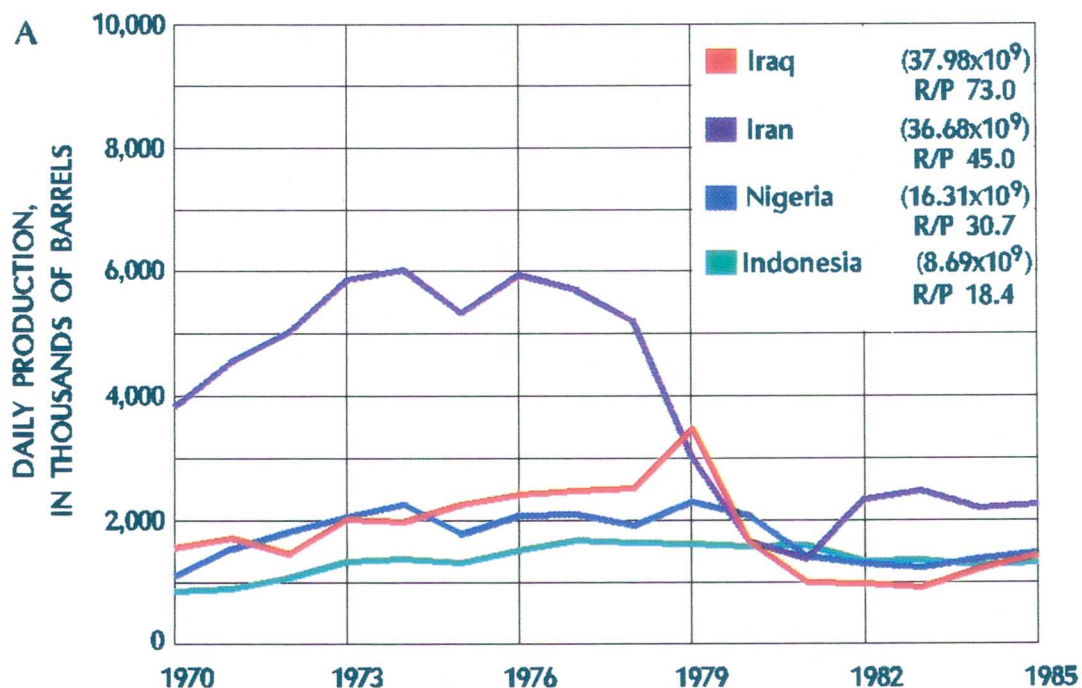


Figure 8. Continued.



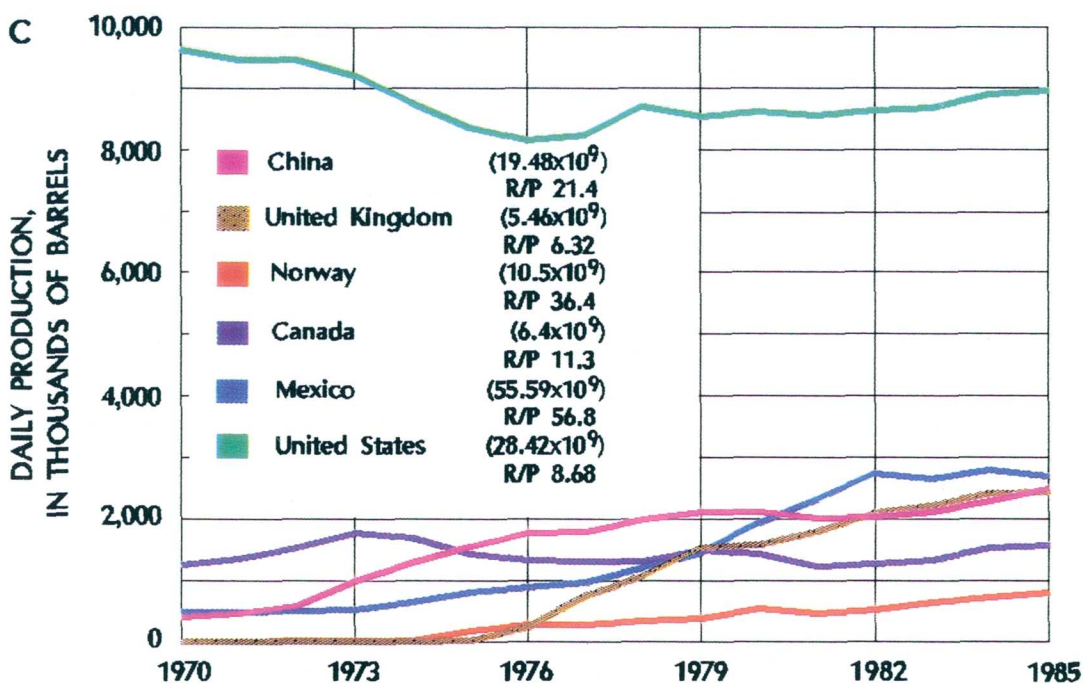
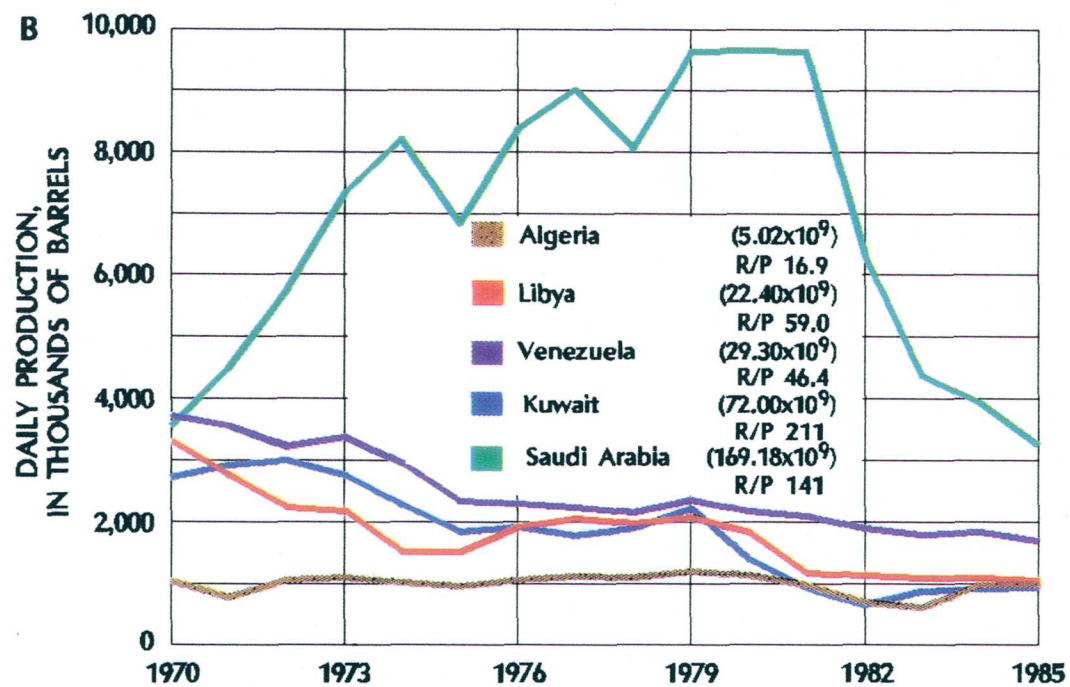


Figure 9. Continued.

variables combine in an optimum way. In the case of petroleum, the critical variables are petroleum source rock, reservoir rock, trap, and timing. The optimum combination of these variables is rare, and the localized concentrations of large accumulations of petroleum around the world prove this point. With the possible exception of deep-water continental margin areas, it is unlikely that a major district remains undiscovered that might significantly alter the known distribution of world oil.

SITUATION AND OUTLOOK FOR PETROLEUM RESOURCES IN THE UNITED STATES

In 1950, U.S. consumption of crude oil and refined products was 2.5 BBO, of which U.S. imports were only 11 percent. By 1977, both consumption and imports reached a historic high; 6.8 BBO were consumed, of which net imports were 44 percent. After a succession of supply and price shocks, the United States cut both annual consumption and imports; in 1985, 5.7 BBO were consumed, of which net imports were 28 percent.

An important aspect of the U.S. import picture has been the progressive shifting from one set of suppliers to another (figs. 10, 11). Until 1972, at least half of all oil imports were from the Western Hemisphere. From 1972

to 1981, at least half were from Africa and the Middle East. Since 1981, oil imports have been more evenly divided between the major producing areas of the world. These shifts reflect both the more limited resources of the Western Hemisphere and company exploration strategies. The traumatic effects of the OPEC oil embargo in 1973–1974 and the large price increases in 1979 motivated attempts to decrease U.S. dependence on oil in general and on imports from Middle Eastern nations in particular. Although the initial goal of energy independence has gradually given way to a recognition of the inevitable interdependence of the world oil market, the United States has moved to attain more diverse and stable supplies of foreign oil.

Approximately 4 billion barrels of petroleum liquids are produced annually in the United States; slightly more than 3 billion barrels are liquid crude oil, and about 0.6 billion barrels are liquids from gas. The outlook for continued production at this level is somewhat uncertain geologically. One point of uncertainty in the near term is the amount of oil being added to reserves by discoveries of new fields. Since 1979, the U.S. Government has not collected information that allows an accurate accounting of exploration finding rates and new-field wildcat-well successes, but about one-sixth of annual additions to reserves generally can be attributed to wildcat exploration. The remainder of the additions to reserves is attributed to extensions of known fields, reassessment of reserves in

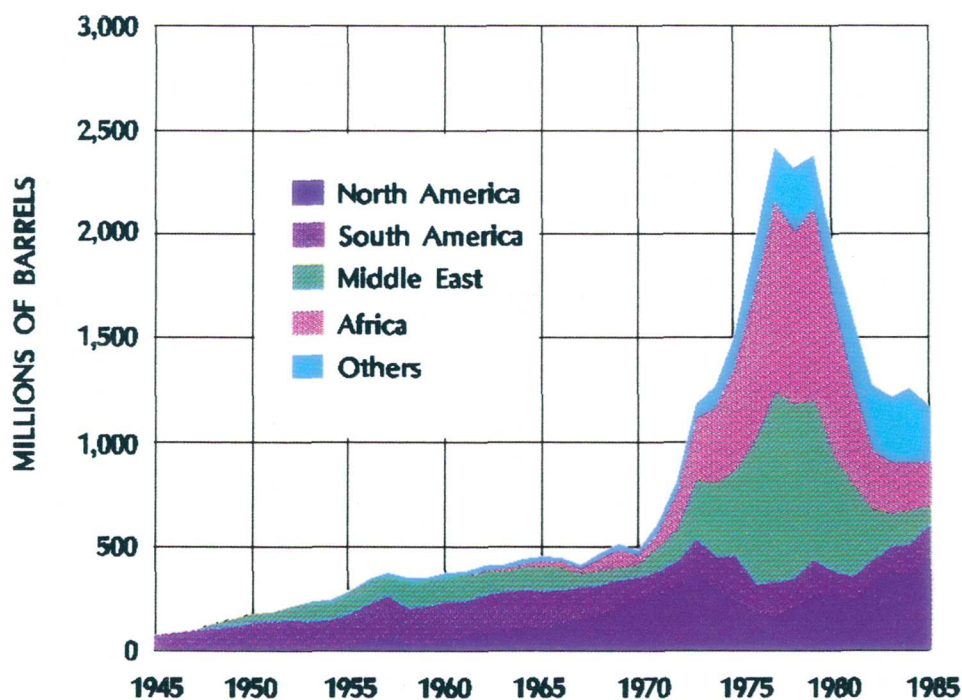


Figure 10. U.S. imports of crude oil by source region, 1945–1985. Modified from DeGolyer and MacNaughton (1986, p. 58).

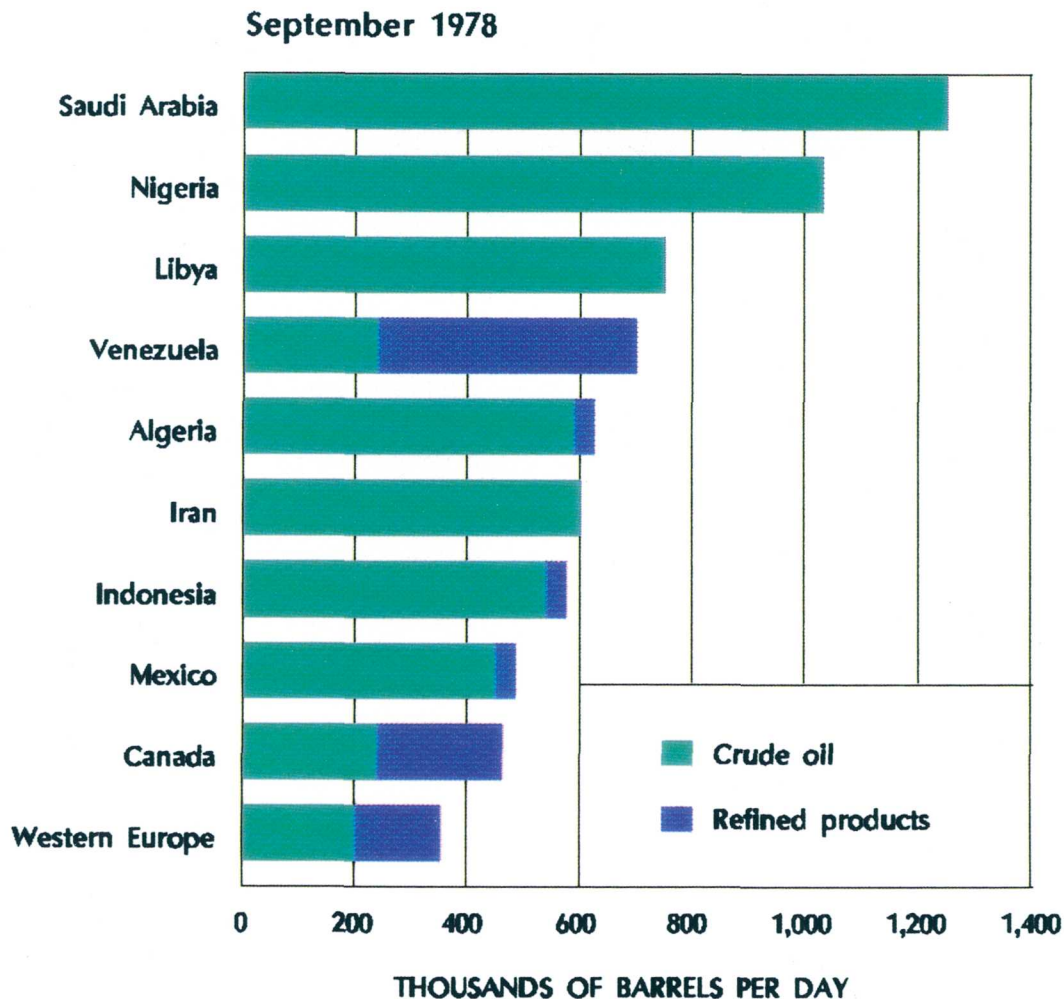


Figure 11. Major sources of U.S. imports of crude oil and refined products, 1978 and 1985. Modified from Borg (1986, p. 4).

known reservoirs, and discoveries of new reservoirs in old fields.

Another point of uncertainty in the relatively near term is the outlook for growth in known fields. For each of the past few years, about 2.5 BBO have been extracted from known conterminous U.S. reserves; yet, until the industry decline of 1986, U.S. proven reserves were believed to have remained the same or increased slightly. If this picture of reserves is true, new reserves are being developed in old fields instead of fixed reserves simply being drained at a faster rate. In other words, oil contained in a rock reservoir and previously not considered to be drainable in normal recovery operations now is being brought into production. Some of the addition results from enhanced oil recovery, but much more apparently comes from in-fill drilling. The important question is how long such additions to reserves can continue simply as a result of drilling more wells in known fields. A corollary question is how much similar growth we can expect in the

few new fields being discovered each year. Other related questions are the rate at which we can expect this assumed new reserves addition to become available, the cost, and whether this field growth has been factored adequately into estimates and inferences of undiscovered recoverable oil resources. To answer these questions will require detailed knowledge of the geologic character of many representative reservoirs.

In the longer term, a major uncertainty lies in estimates of undiscovered recoverable resources. In 1981, the USGS (Dolton and others, 1981) produced an estimate of undiscovered resources that ranged from 64.3 BBO (95-percent likelihood) to 105.1 BBO (5-percent likelihood), the mean being 82.6 BBO. Since that time, exploration disappointments have occurred in areas once considered to be among the most promising U.S. frontiers. Unproductive drilling in two major prospective areas of the Atlantic margin indicates a much lower likelihood of significant resources than previous forecasts had sug-

August 1985

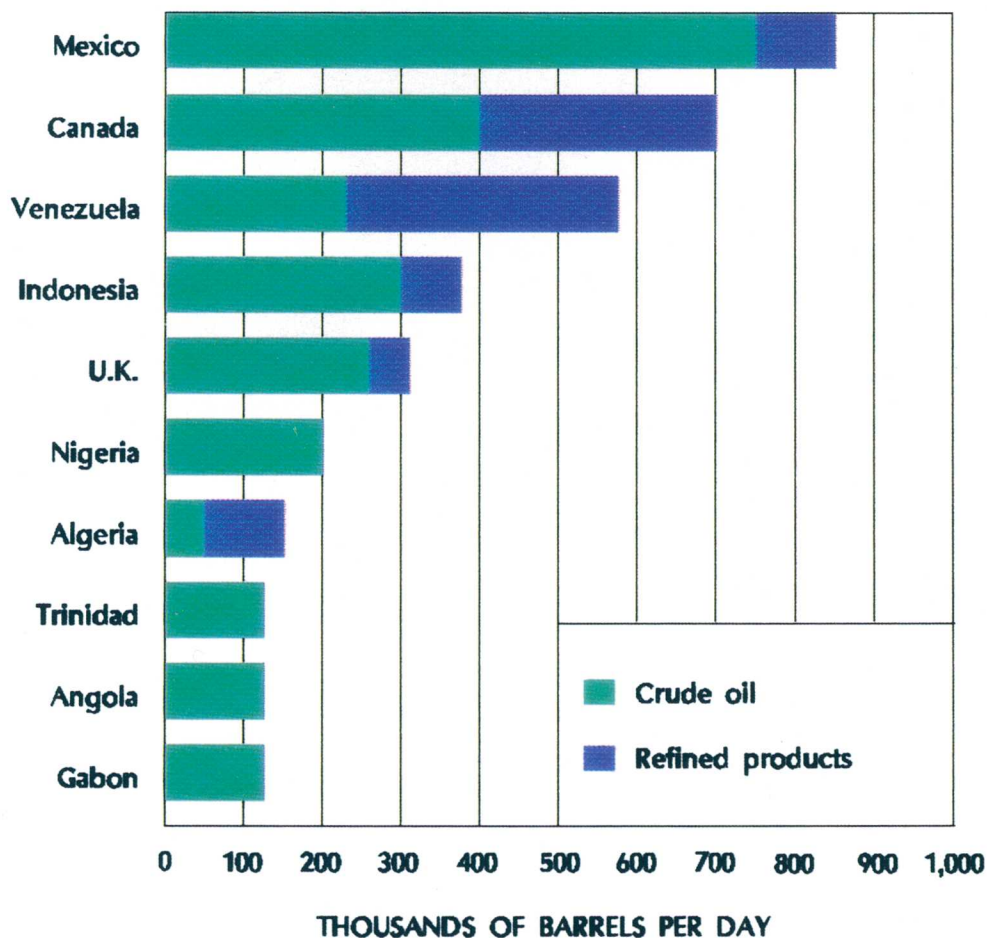


Figure 11. Continued.

gested. Results from a few holes drilled in the Navarin basin of the Bering Sea continental shelf indicate that the sedimentary rocks are much less favorable hosts for large occurrences of oil than investigators had previously believed. The Mukluk structure off the North Slope of Alaska, once believed to resemble in promise the nearby structure containing the supergiant Prudhoe Bay oil field, was drilled and appears to be barren. Recent noteworthy finds in the deep-water parts of the Gulf of Mexico and in offshore California are unlikely to compensate for these major exploration disappointments. Oil exploration and development in an area of major promise on the North Slope, the Arctic National Wildlife Refuge, hinge on the outcome of the debate about the relative value to society of potential energy resources as opposed to preservation of wilderness. Currently, the area is closed to petroleum resource development, but the Secretary of the Interior recently recommended to Congress that exploration be permitted. Highly prospective areas of offshore Califor-

nia also are subjects of controversy and, at this time, are closed to exploration.

Estimates of offshore oil potential made in 1985 by the Minerals Management Service (MMS) (Cooke, 1985) indicate a decrease, by almost 50 percent, in expected recoverable resources relative to estimates made by the USGS in 1981. Part of this decrease reflects economic differences between 1981 and 1985, such as oil price expectations and minimum economically exploitable field size in areas such as the Arctic, and part is because the MMS estimate did not cover deep-water or State-owned areas included in the USGS estimates. Much of the decrease results, however, from the new and less optimistic geologic information discussed above. Revised estimates of the undiscovered recoverable resources of the United States now being prepared by the USGS and the MMS may be 25 to 50 percent lower than the 1981 estimates.

An important factor in evaluating the petroleum resource potential of the United States is that it is at a very

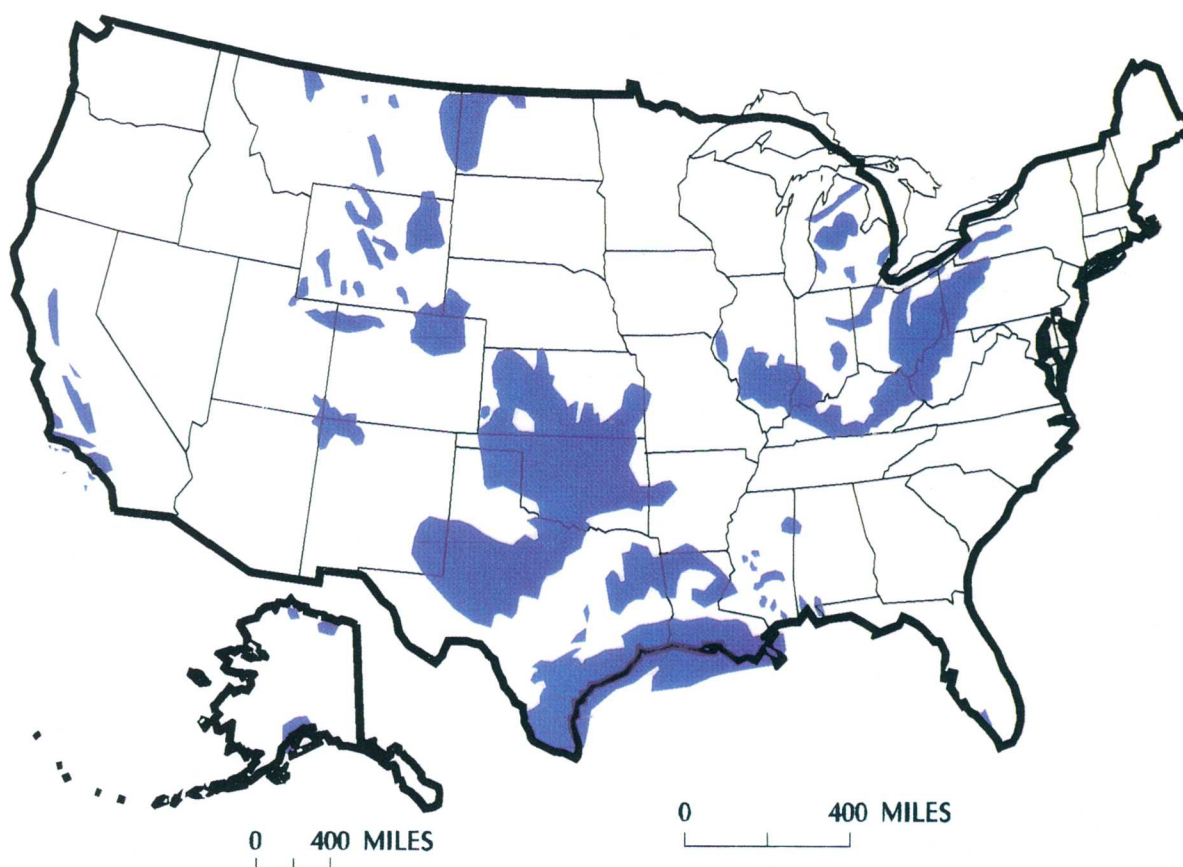


Figure 12. Oil and gas fields in the United States. Modified from K.L. Varnes (written communication, 1987).

mature stage of exploration. Oil fields are widely distributed (fig. 12), and few undrilled major frontiers remain. Moreover, the distribution of oil resources is highly skewed toward large fields (greater than 10 million barrels), especially giant fields (greater than 100 million barrels). Fields larger than 10 million barrels constitute only about 5.5 percent of total U.S. fields, yet they contain 77.5 percent of U.S. oil reserves. It is unlikely that a significant number of giant or supergiant fields remains to be found in the exploration frontiers of the United States. The lack of new giant fields and the increasing difficulty of finding more oil in a well-explored country are reasons behind the dramatic decrease since about 1950 in oil discovery rate per foot drilled (fig. 13). On the other hand, results of statistical analysis of oil pool distribution suggest that as many as 110,000 additional fields remain to be found. Many of these fields will be too small to be economic under any circumstances, but many others will be productive. Cumulatively, these fields may extend U.S. reserves by several years of annual domestic production, but they will be hard to find and will not necessarily be available when they are most needed.

Although gas is an important energy resource, particularly for residential and industrial heating uses, it

cannot readily replace liquid hydrocarbons. The United States currently consumes about 17 trillion cubic feet of gas (TCFG) per year. In 1981, the USGS (Dolton and others, 1981) estimated measured U.S. gas reserves at 191 TCF and inferred reserves at 177 TCFG. Undiscovered recoverable gas resources were estimated between 475 and 740 TCFG, the mean being 594 TCFG. As with oil estimates, the range and mean reflect statistical probabilities, from high to low confidence, estimated by groups of experts that evaluated the petroleum geology and exploration history of 137 provinces. The estimates are based primarily on publicly available data and conventional technology and economics and do not include gas from unconventional sources. The estimates reflect assumed economic thresholds, such as minimum field size and availability of delivery infrastructure; these threshold values could be very important in determining the amount of gas that ultimately can be produced from frontier areas such as Alaska or deep-water areas of the continental slope.

As with oil reserves, a large percentage of the gas reserves are in giant (greater than 0.6 TCFG) and supergiant fields. The United States has only 2 supergiant and 17 giant gas fields, which, along with some large but

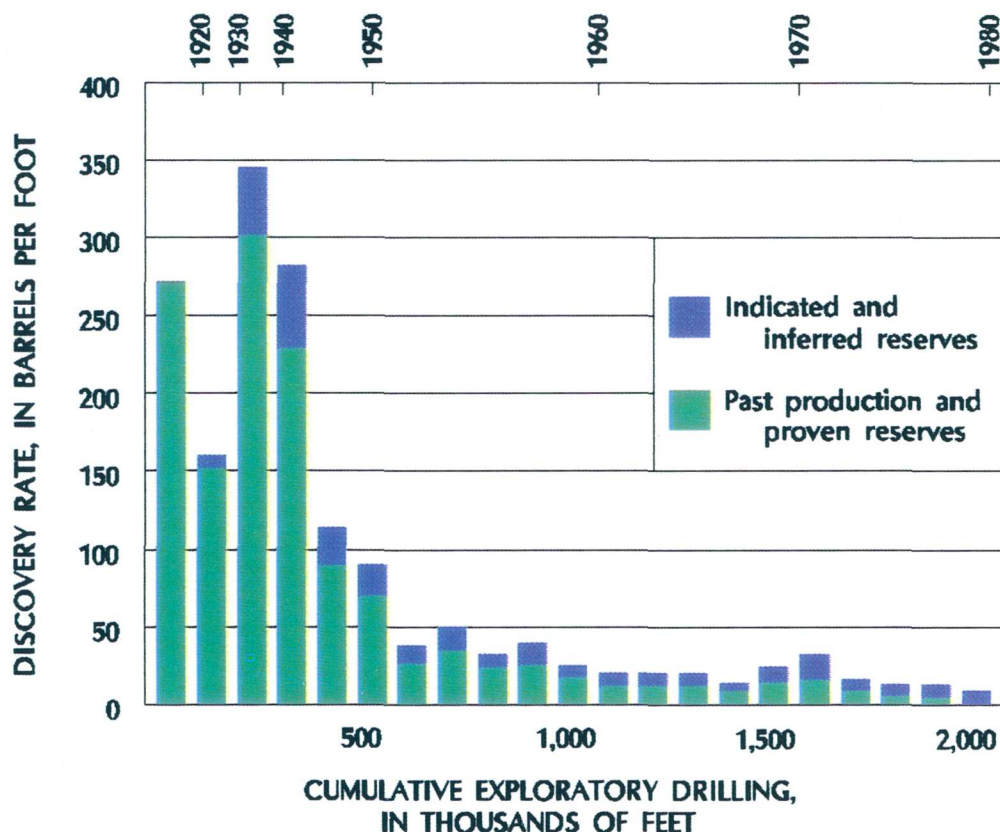


Figure 13. Discovery rate of crude oil in the United States as a function of the cumulative amount of exploratory drilling, 1920–1979. Modified from C.D. Masters (written communication, 1986).

not giant fields, are critically important. Of some 9,000 gas fields in the United States, the largest 100 contain about half the estimated U.S. gas reserves; the Prudhoe Bay field alone is estimated to contain 26 TCFG. At present, however, the gas in the Prudhoe Bay field cannot be delivered for lack of a pipeline, a reflection of the general logistical and economic problems limiting gas production in Arctic and offshore frontiers.

The outlook for U.S. gas exploration and resource development is related to oil supply and price. Lower oil prices are likely to delay or change plans by consumers to shift from oil to gas and will seriously affect the minimum field size necessary to warrant economic development of gas, especially in difficult frontier areas. Some important potential resources may not be economic to produce.

THE ROLE OF GEOLOGIC INFORMATION

Whether the goal is exploration in frontier areas, effective drilling to find new fields in known areas or new oil in old fields, or development of improved production methods to obtain all the oil possible from a well, it is critical to have the best possible geological information and insights.

Initial targets in the exploration of frontier basins generally are geologic structures interpreted from seismic reflection data, such as folds, faults, salt domes, or ancient reef complexes. The likelihood that such structures will contain petroleum is gauged by using the best possible knowledge of the geologic framework and history of the basin and comparison with other productive basins. The necessary geologic knowledge encompasses (1) the regional geology of the target area and how it might provide a setting for the occurrence of petroleum; (2) a determination of the amount and type of organic matter in the rocks, including the extent to which it may have been altered by heat into mobile hydrocarbons; (3) the character, volume, and position of various source rock and reservoir rock units; (4) the configuration and volumes of apparent trap structures; and (5) the likelihood of seals above or around traps that would keep oil or gas from escaping. Information from rock exposures and samples from drill holes must be used to make observations or inferences about the extent of porosity and permeability and the geologic processes that may have affected these reservoir rock characteristics. Frontier exploration, particularly in Arctic or offshore areas, is very difficult and

expensive, and each element of geologic information is critical.

Detailed geologic information also is required before drilling in known areas to find new resources. Local geologic settings within an oil basin should be deciphered to infer conditions of reservoir sand deposition, the resulting inhomogeneities of these sands, and the likely distribution and geometry of potential reservoirs. To optimize in-fill drilling or to improve oil and gas recovery techniques, detailed information is required on the reservoir rock's pores, how they are interconnected, and by what minerals they are enclosed. As new information and insights on regional geology and on the occurrence of petroleum are obtained, exploration strategies and field

development techniques are improved, and better estimates of the petroleum resources of the United States can be made. Studies of petroleum geology by the USGS have been designed to meet both short- and long-term needs and to provide some continuity of research effort, a particularly useful function during times when industrial research and exploration efforts are severely curtailed. They include basic research on reservoir rock characteristics and the processes that affect them, studies of the regional and petroleum geology of selected frontier areas, studies of geologic basin processes that give rise to petroleum provinces, and resource assessments that offer an informed basis for government decisions on land use and national energy policies.

Focus: Oil and Gas Resources on Wilderness Lands

The Federal Government owns approximately 738 million acres of onshore land in the United States, almost one-third of the Nation's entire land area, and it retains control over subsurface mineral rights to an additional 66 million acres.

Approximately 50 percent of these Federal lands is in the 11 Western States. In 1981, 31 percent of this land was classified as designated and proposed wilderness land, and access to exploration and development was limited. The Wilderness Act of 1964 stated that, after December 31, 1983, these areas were to be off limits to energy and mineral exploration and development. In recent years, controversy has been generated in regard to the probable occurrence of energy and mineral resources on Federal lands in general and on wilderness lands in particular. A major issue is whether it is in the best interests of the United States to allow resource exploration and development on Federal lands, especially those having noteworthy environmental values.

Various resource studies on limited segments of these Federal lands by government and industry indicate that an important part of the future energy and mineral resources of the United States may lie beneath federally controlled lands. The accuracy of these resource estimates is unknown, however, because only limited data are available regarding resources on most Federal lands.

As part of the USGS's responsibility to inventory the Nation's resources, in particular those on Federal lands, a pilot study was conducted in 1982-1983 to assess the potential for oil and gas resources in designated and proposed wilderness lands of the Western United States (Miller, 1983). The scope of the investigation was limited to conventional petroleum resources occurring in wilderness lands administered by the Bureau of Land Management, the Forest Service, the National Park Service, and the Fish and Wildlife Service. The area of study included almost 74 million acres in Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

This study was the first Federal program of systematic geologic studies of the petroleum resource potential on specifically designated Federal lands. The wilderness

areas in each State were identified as to controlling agency, and the potential for the occurrence of petroleum resources in each area was assessed. At least 34 percent of the wilderness lands, or about 25 million acres, was determined to have the geologic attributes necessary for the occurrence of petroleum resources. An additional 33 percent is mostly in areas where small amounts of sedimentary rocks are mixed within igneous and metamorphic terranes and was determined to have either limited or unknown potential for petroleum resources. The remaining 33 percent is located in terranes containing predominantly igneous and metamorphic rocks and probably has no petroleum resource potential; however, these terranes may have potential for various mineral resources.

Seventy percent (or 52 million acres) of the wilderness land studied is proposed for withdrawal from exploration; the remainder (22 million acres) has already been designated as wilderness land by law. A significant result of this study is that, of the 25 million acres believed to contain petroleum resources, 21 million acres are wilderness lands proposed for withdrawal, and only 4 million acres have already been withdrawn from exploitation.

Estimates of undiscovered conventional recoverable crude oil resources on the lands studied are from 600 (95-percent likelihood) to 1,490 (5-percent likelihood) million barrels, the mean estimate being 834 million barrels. Estimates of undiscovered conventional and recoverable natural gas resources are from 5.54 to 16.64 TCFG, the mean estimate being 9.73 TCFG. Most of the oil resource is in Wyoming, Idaho, and Utah, and most of the gas resource is in Wyoming, Montana, and Idaho.

This pilot study indicates the value of inventorying the energy and mineral resources of the United States as a basis for informed decisionmaking in the balanced management of public lands to maximize use of those lands for the public benefit. A similar detailed assessment of the petroleum resources of all Federal lands is now being prepared as part of the revision of estimates of the undiscovered petroleum resources for the entire United States.

Focus: Frontier Petroleum Province in the Eastern United States

About 180 to 240 million years ago, during the Triassic and Jurassic periods, an extensive system of fault-bounded sedimentary basins developed along the eastern margin of North America as a result of continental rifting and formation of the Atlantic Ocean. Resource assessment and exploration for petroleum and minerals in these rift basins are hampered by a lack of outcrop in the exposed basins and by thick sedimentary cover over buried basins on the coastal plain and offshore.

Organic geochemical studies of these basins were initiated to evaluate their petroleum resource potential and to determine the relationship between organic matter and mineralization. Preliminary studies focused on a thick sequence of organic-rich shales in the Triassic part of the Newark basin, but these shales have an unfavorably high temperature history with respect to petroleum generation and preservation. Recent systematic sampling of Triassic and Jurassic rocks, however, has revealed the presence of less thermally altered shales of Early Jurassic age in the Hartford (Connecticut and Massachusetts) and Newark (New Jersey, New York, and Pennsylvania) basins. A clear precursor-product relationship exists between indigenous organic matter in the Jurassic shales and migrated organic matter (liquid and solid) in overlying hydrocarbon-stained sandstones and vein fillings.

Mineralized veins commonly crosscut sedimentary and volcanic rocks in the Hartford and Newark basins.

The history of fluid flow in the basins was reconstructed through studies of the composition and texture of these veins. Results of the studies indicate that multiple generations of mineralizing fluids and petroleum fluids migrated through open fractures in the rocks.

In the Hartford and Newark basins, the zone of petroleum source rocks is believed to be about a kilometer thick and to encompass the boundary between Triassic and Jurassic rocks. A brief episode of high heat flow during the earliest Jurassic is proposed to account for the narrow, shallow zone believed to have generated oil. Extensive Jurassic lava flows probably were associated with this time of high heat flow.

In the exposed rift basins, most potential petroleum reservoir rocks have been removed by erosion, but, wherever the upper part of the rock section is preserved, exploration targets are shallow and relatively inexpensive to drill. The presence of thin but widespread organic-rich shales having moderate to excellent petroleum source potential indicates that reservoir properties rather than thermal history or source rock quality limit petroleum accumulation. The potential for petroleum accumulation is greater in the buried basins than it is in the exposed basins because less erosion of possible reservoir rocks has occurred. The regional geologic setting, good quality of potential source rocks, and presence of migrated petroleum in the exposed basins are cause for optimism about resource prospects in the buried basins.

Focus: Magnetic Exploration for Oil and Gas Fields

The possibility that magnetic methods can be used to locate hydrocarbon accumulations was first suggested by T.J. Donovan of the USGS in 1979, following the identification of anomalous magnetic signals from shallow rocks above the Cement oil field of central Oklahoma. Upward leakage of hydrocarbons from deep reservoir rocks was suggested as the mechanism that generated geochemical conditions favorable for the growth of a strongly magnetic iron-oxide mineral (magnetite) in near-surface rocks. More recently, magnetic anomalies were recognized over other developed oil fields and over some undeveloped areas that have a high potential for hydrocarbons, but the original theory was not systematically tested. The sources of the anomalies—that is, the magnetic substances that cause them—were unknown, and evidence relating the anomalies to hydrocarbons at depth was lacking.

Geophysical, geologic, and geochemical methods are being used in three areas of anomalous magnetization to test the original theory. The test areas are (1) the Cement oil field, which has been developed; (2) an area in Alaska that represents a known but undeveloped oil field; and (3) an area in Idaho and Wyoming that shows high promise for oil and gas resources. Studies in the Cement oil field indicate that an unusual magnetic iron-sulfide mineral, pyrrhotite (fig. 14), formed in abundance in shallow rocks directly above the field and that formation of the pyrrhotite is closely related to leaking hydrocarbons; magnetite was not observed in these rocks. Anomalous magnetization in an oil field in Alaska's North Slope also is caused by a magnetic iron-sulfide mineral—in this case, greigite, the formation of which may be related to oil leakage. In the central part of the Idaho-Wyoming thrust belt, magnetic anomalies on trend with nearby gas and oil

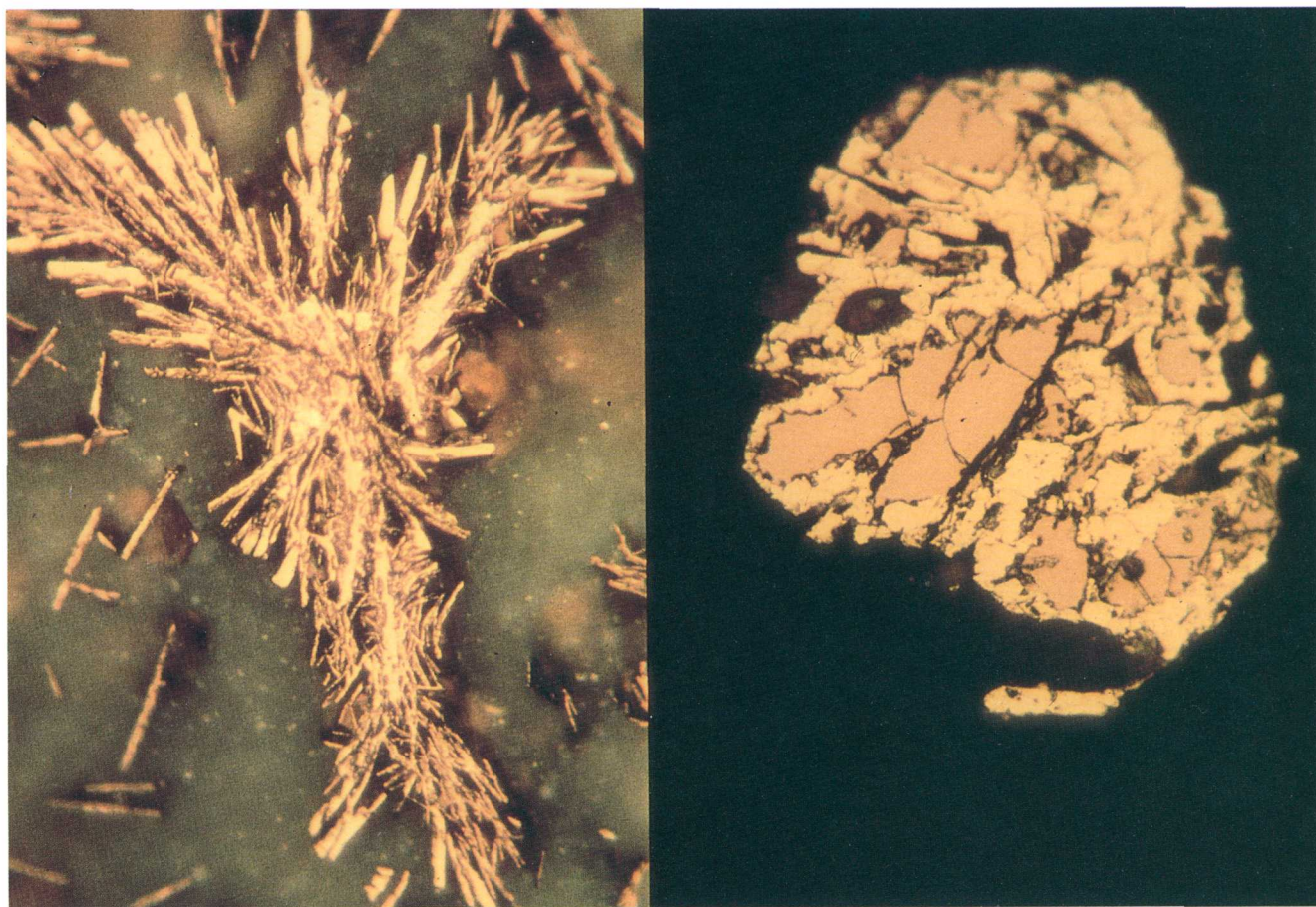


Figure 14. Photomicrographs of pyrrhotite in well cuttings from the Cement oil field of Oklahoma. The pyrrhotite formed in shallow rocks directly above the field, and its formation was closely related to leaking hydrocarbons. *Left*, Mosaic of pyrrhotite plates within mudstone. *Right*, Tabular crystals of pyrrhotite partly replaced by pyrite.

fields to the south are caused by magnetite, but, because the magnetite was present when the rock formed, the anomalies are not related to hydrocarbon leakage.

Preliminary studies indicate that certain hydrocarbon seepage environments are favorable for the genera-

tion of anomalous magnetic signals, whereas other environments are not. Future geologic studies will focus on developing models to distinguish between favorable and unfavorable environments and should lead to more effective and reliable applications of this exploration technique.

Focus: The Monterey Formation of California

The Monterey Formation of Miocene age is a fine-grained organic-rich siliceous rock unit of great economic importance. Long known as a major source rock for oil, the Monterey is also a prolific reservoir rock, both onshore and offshore in a series of California basins (fig. 15). Oil has been produced from the Monterey since the late 1800's, but very recent discoveries show the particular importance of fractured-rock areas as exploration targets in the siliceous formation. The Point Arguello field, reported to contain on the order of 500 million barrels of recoverable oil (Isaacs and Petersen, 1987), is a major fractured-rock reservoir offshore in the Monterey, and the regional geologic framework of the formation suggests much promise of other such petroleum occurrences.

Fractured rocks are not a common reservoir type, and almost all oil reservoirs worldwide have been discovered in porous, permeable rock layers where oil is trapped in relatively large pores by overlying impermeable layers. As a result, well log analysis and other techniques for locating oil have focused on finding high-porosity zones. In the Monterey, however, oil is trapped in rocks having

many but very small pores, and oil production is possible only because extensive fractures connect the pores and increase rock permeability. Conventional well log analysis has not proved very helpful in recognizing fractured-rock reservoirs, but exploration techniques developed for the Monterey should prove valuable in recognizing other fractured rocks.

Other exploration challenges abound in the Monterey. The formation is thinly bedded and highly diverse, and correlating rock sequences from one basin to another typically has been more guesswork than science. Post-depositional chemical changes in the rocks have variably altered the character of potential reservoir rocks from one basin to another, as well as within a basin. Organic matter in the Monterey has been interpreted through conventional analysis as not having matured (been altered by heat) sufficiently to generate oil, even where oil accumulations have been discovered.

For the past several years, research by USGS scientists has been aimed at deciphering the character and history of the Monterey Formation. One of the major problems addressed was how to determine regional trends

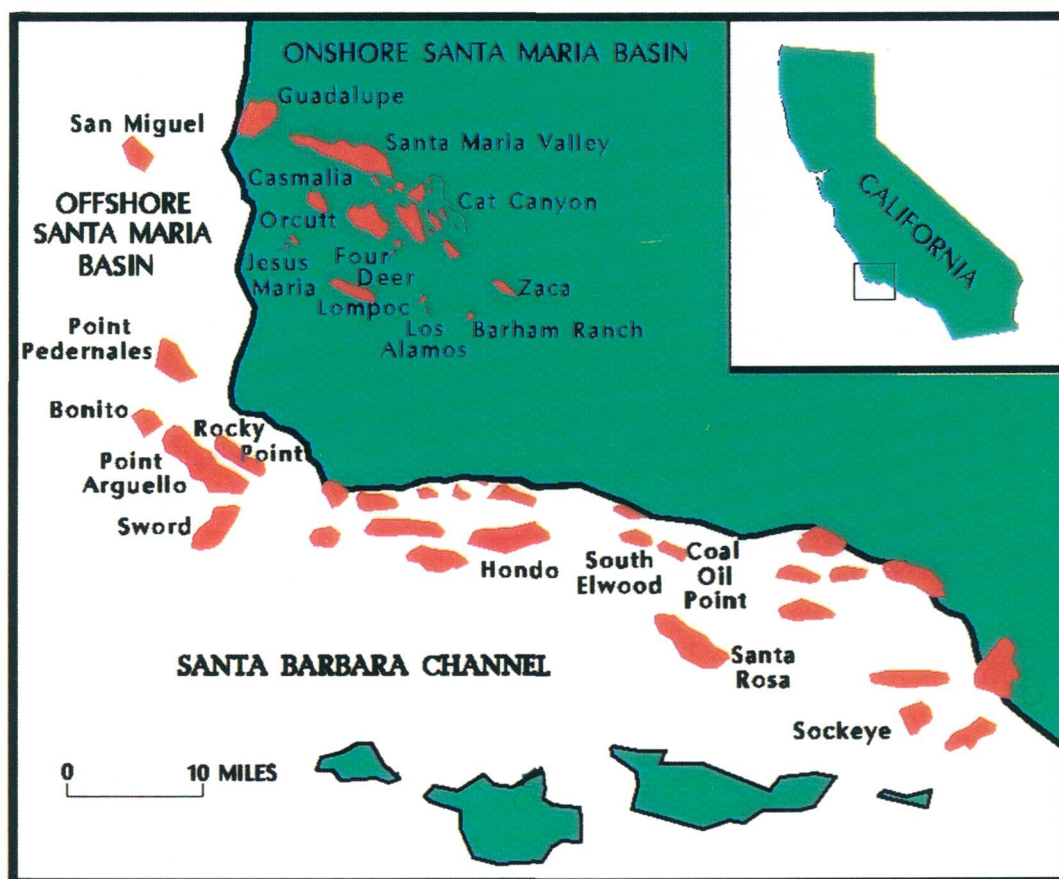


Figure 15. Onshore and offshore oil fields (red) in the Santa Maria basin of California.

ORCUTT FIELD WELL #8

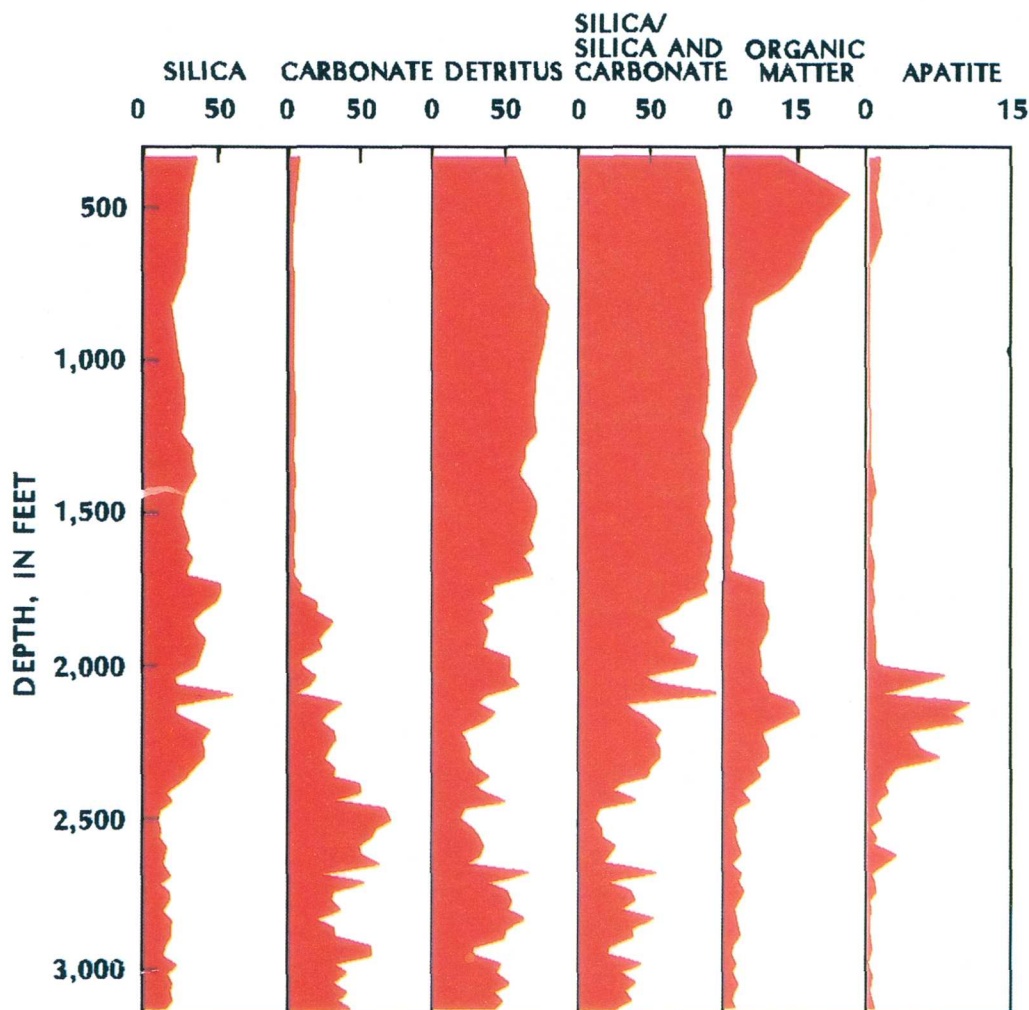


Figure 16. Chemical analyses of well cuttings from the Monterey Formation provide a basis for detailed stratigraphic correlations.

in the distribution of rock types according to particular origin and character. The Monterey is composed of three types of sedimentary rocks: rocks composed of fine-grained, biologically produced marine sediment, which become highly fractured as a result of chemical changes during burial; rocks composed of fine-grained land-derived sediment, which are less fractured; and rocks containing organic matter, the source of the oil. Regional trends of these sedimentary components have been difficult to determine because of the formation's thin-bedded nature and diverse rock types. A major accomplishment was the successful testing of whole-rock chemical compositions of well cuttings as a tool to determine the average composition of many thin beds and thus categorize some of the diverse rock sequences (fig. 16).

Rates of sedimentation in the various Monterey Formation basins were also determined. The Monterey,

even where it is most siliceous, did not result from an unusually rapid, biologically derived influx of silica but rather from an extremely slow influx of diluting land-derived sediment. The discovery of this relationship led to the important conclusion that regional facies trends were controlled principally by the supply of land-derived sediment rather than by the supply of biologically produced ocean sediment. Understanding the distribution of rock types in the Monterey thus requires focusing on the geologic processes that influenced the influx of sediment from land rather than on those that influenced the supply of material from the marine environment.

It was also recognized that use of normal measurement techniques results in a significant underestimation of the alteration of the organic matter in these unusual rocks. In fact, during early burial and before compaction, the sediments most likely were not only much thicker but

also were subjected to high temperature gradients. As a result, alteration (maturation) of organic material was more advanced at an earlier stage in basin development than investigators had previously realized.

These recent studies have produced a new understanding of the enormously productive and prospective

Monterey Formation. From studies of regional setting and geologic history to detailed geochemical research designed to show the origin of oil and the changes that have occurred in the reservoir rocks, the new information provides an improved basis for selecting exploration targets and interpreting exploration data.

Focus: Assessment of Petroleum Potential in the Arctic National Wildlife Refuge, Alaska

The coastal plain area of the Arctic National Wildlife Refuge in northeastern Alaska is an arctic environment where wildlife protection is an important concern. It is government-owned land currently under consideration for leasing for petroleum exploration, and Section 1002 of the Alaska National Interest Lands Conservation Act required the U.S. Department of the Interior to evaluate both the wildlife resources and the potential for petroleum resources, so that Congress could make a well-informed decision about possible leasing. A consortium of oil companies was permitted to conduct some 1,300 miles of seismic surveys, and data from those surveys and other surface exploration were turned over to the USGS and the Bureau of Land Management for assessment of the area's oil and gas potential. The USGS estimated in-place resources, and the Bureau of Land Management overlaid economic and engineering factors to produce estimates of recoverable resources. A report to Congress on both the

resource assessment and the environmental aspects of this important and controversial area of arctic land was issued in early 1987 by the U.S. Department of the Interior. The large oil and gas resource potential assessed was the basis for the Secretary of the Interior's recommendation to Congress that the area be opened to petroleum exploration.

Both the supergiant Prudhoe Bay field, which lies about 60 miles west of the refuge border, and the nearby smaller Kuparuk field produce oil from a complex of rocks called the Ellesmerian sequence. These rocks extend eastward beneath the coastal plain but vary greatly in thickness owing to an ancient period of erosion. Beneath parts of the coastal plain of the refuge, the Ellesmerian sequence probably is as thick as 5,000 feet. In the eastern two-thirds of the refuge, the rocks are caught up in an "overthrust" belt featuring complicated folds and faults. Figure 17 shows, for one of the reservoir rock units, some

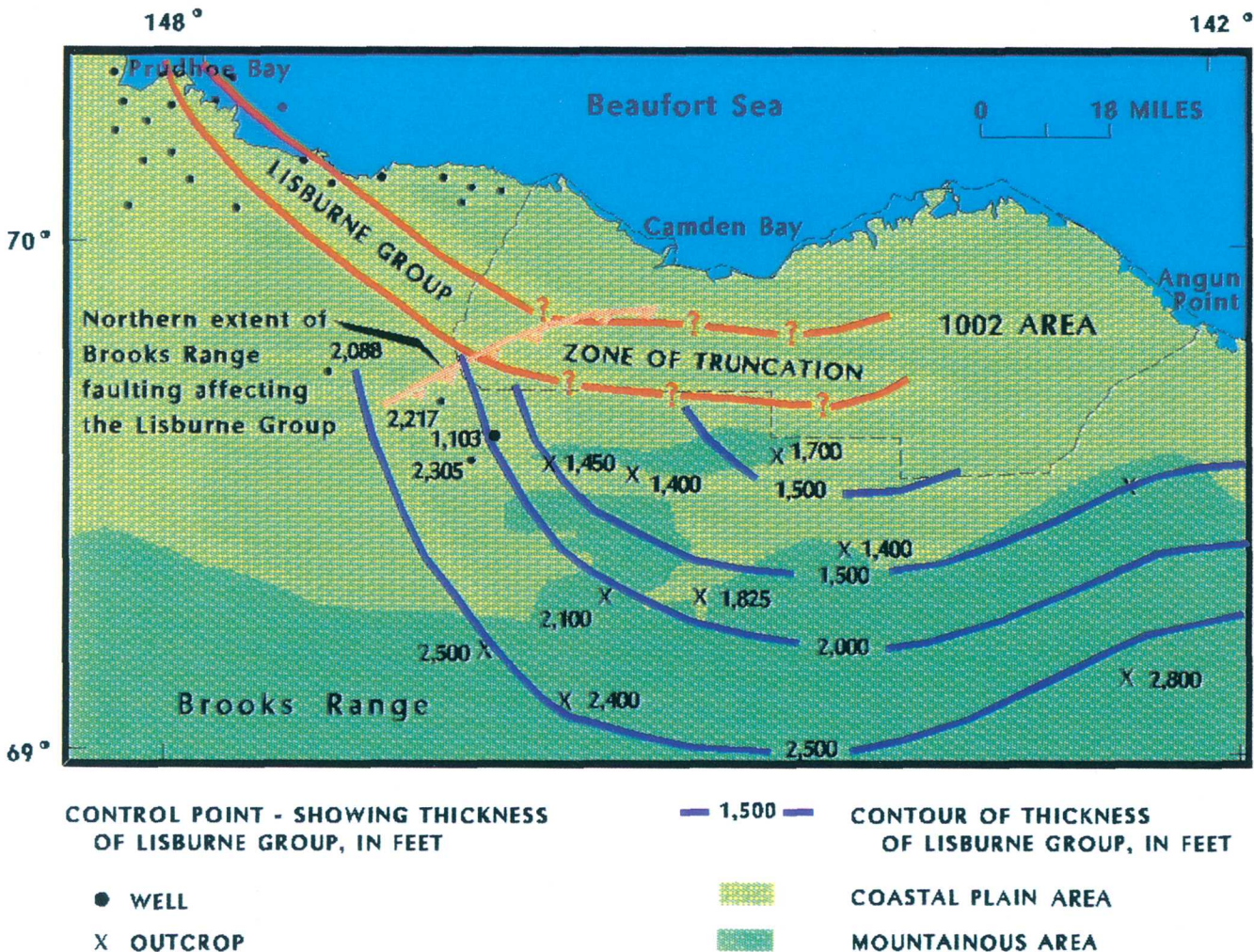


Figure 17. Regional and local geologic trends of the Lisburne Group in the Arctic National Wildlife Refuge of Alaska. Modified from U.S. Department of the Interior (1987, p. 56).

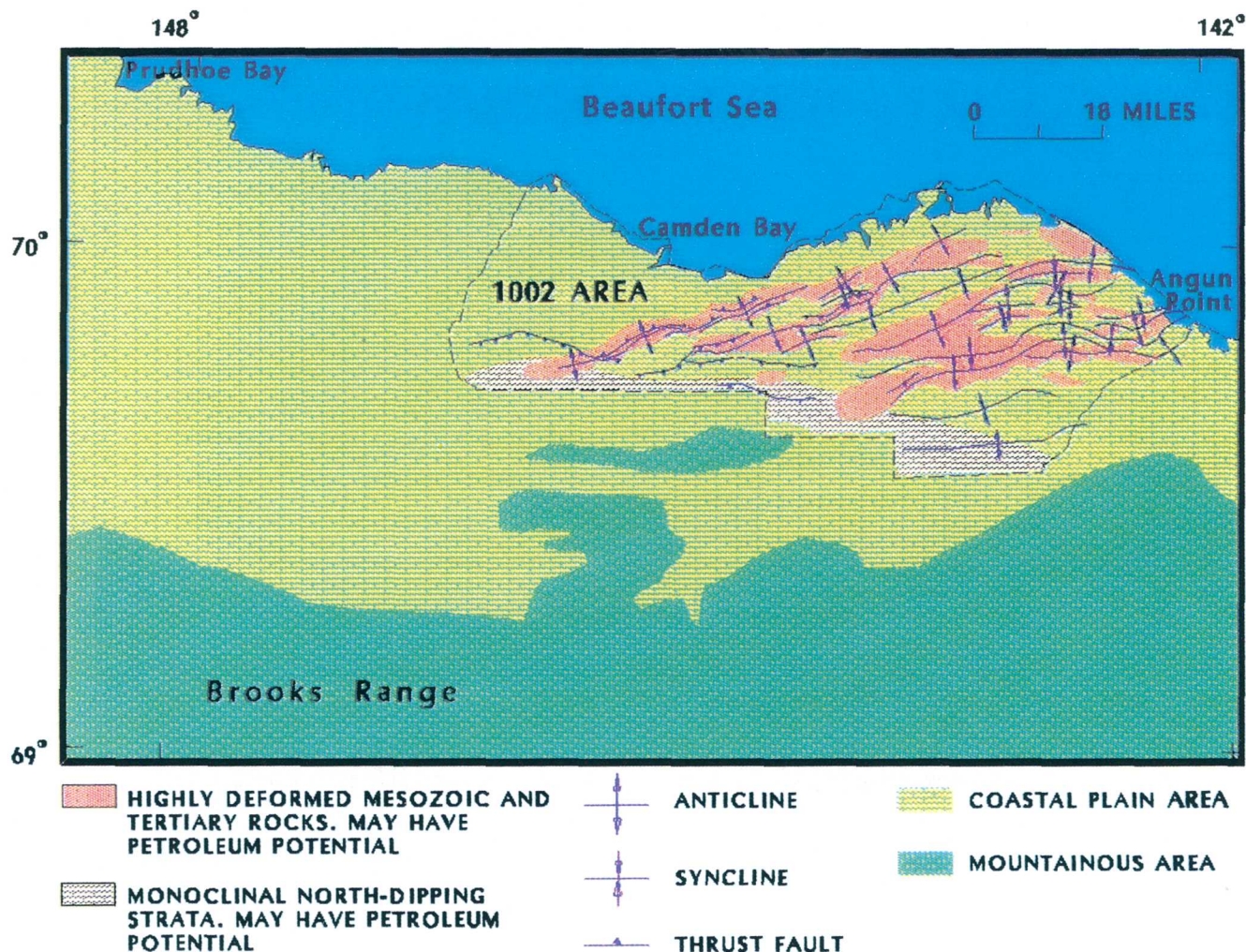


Figure 18. Generalized structural trends in rocks in the Arctic National Wildlife Refuge of Alaska. Modified from U.S. Department of the Interior (1987, p. 60).

of the information available from USGS regional geological surveys and the inferences that such knowledge permits about the continuity of the unit beneath the coastal plain. Without information from drilling, inferences are limited with regard to exactly how much of the Ellesmerian sequence is present, and important details such as organic content and its level of alteration must be either assumed or extrapolated from Prudhoe Bay and other drilled areas outside the refuge and from very limited surface information.

The Ellesmerian sequence is overlain by a very thick group of rocks named the Brookian sequence. Although this sequence is highly prospective to the east in Canada, it is not as promising for oil and gas in the refuge area as the Ellesmerian sequence is. Some petroleum source rocks and potential reservoir rocks do occur, however, in the Brookian sequence. Surface observations and seismic data indicate numerous fold and fault structures that are potential exploration targets, and, in parts of

the area, petroleum seeps have been observed. Figure 18 shows a highly generalized structural geologic interpretation of the Brookian sequence based on available seismic and regional geologic data.

Seven different plays—that is, areas having particular sets of geologic characteristics favorable for oil and gas occurrences—were identified by the USGS. From these plays, in-place oil and gas resources were assessed. According to these estimates, there is a 95-percent likelihood that the assessed area contains more than 4.8 BBO and 11.5 TCFG and a 5-percent likelihood of more than 29.4 BBO and 64.5 TCFG; the mean resource is 13.8 BBO and 31.3 TCFG. Twenty-six prospects within the seven plays were delineated and assessed to estimate how much of the in-place resource might be recoverable (fig. 19). This assessment by the Bureau of Land Management included consideration of technological and economic factors that might limit extraction of the total resource inferred by the USGS for each prospect. It was estimated

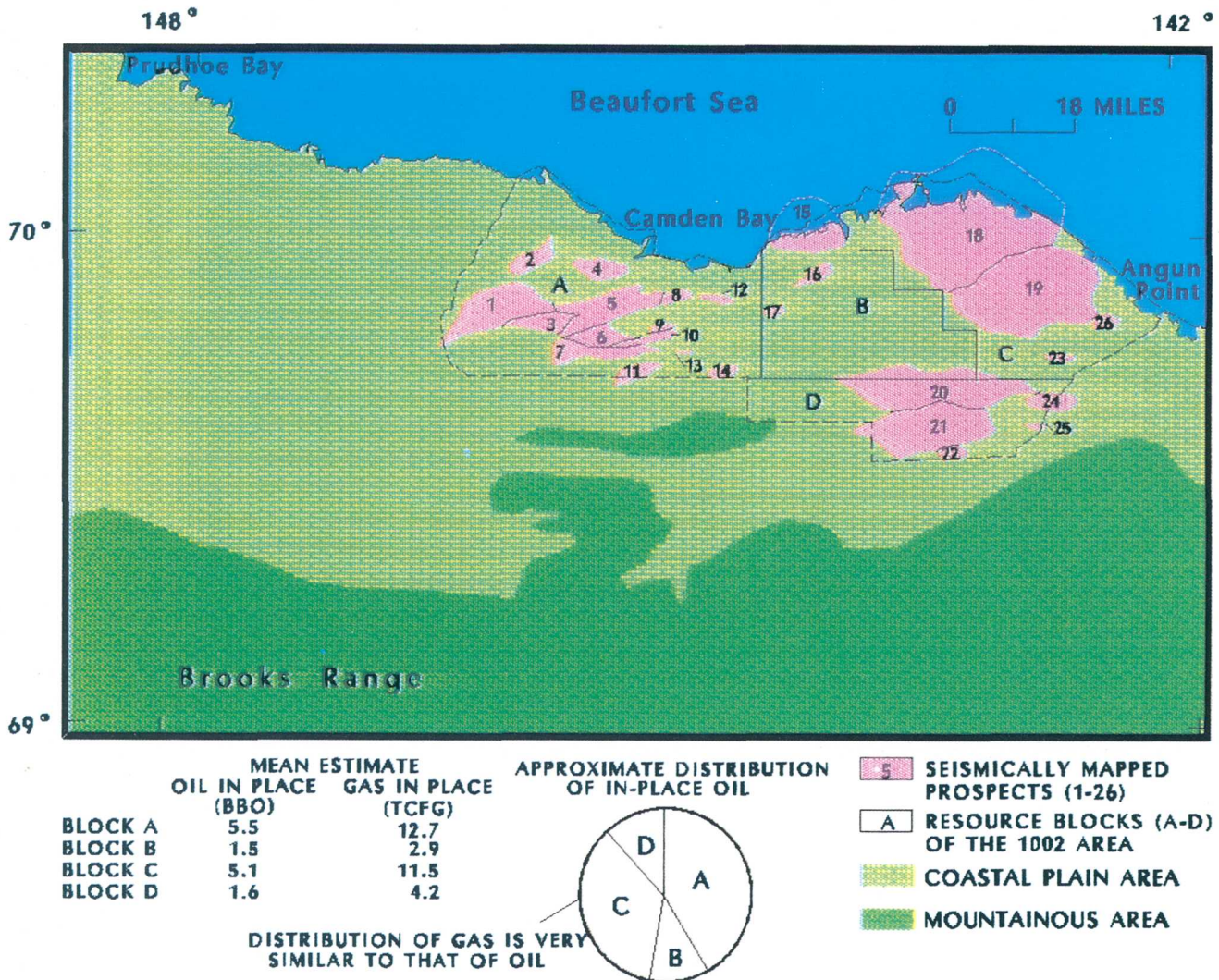


Figure 19. Twenty-six prospects (numbers) in the coastal plain area (Section 1002) of the Arctic National Wildlife Refuge were delineated and assessed for their hydrocarbon potential, primarily by using geophysical (seismic) methods. Oil and gas resources were estimated for four geographic resource blocks (letters). Modified from U.S. Department of the Interior (1987, p. 49, 68).

that, if economically recoverable oil is present (the likelihood of which was estimated to be about 20 percent), there is a 95-percent likelihood for more than 0.6 BBO and a 5-percent chance for more than 9.2 BBO, the mean being 3.2 BBO. There is a very small likelihood that the two largest prospects might contain economically recoverable oil in amounts rivaling Prudhoe Bay. Recoverable gas resources were not estimated, because a gas delivery

system was judged not likely to become available in the foreseeable future. Overall, the favorable setting and petroleum geology of this large area indicate that the Arctic National Wildlife Refuge is one of the most important prospective undrilled areas in the United States. The study, mandated by Congress, is a particularly apt example of geologic knowledge's being recognized as basic to national energy policy decisions.

COAL RESOURCES

The United States is rich in coal resources. Today, coal provides only about 24 percent of the total energy consumed in the United States (fig. 1), but, as conventional oil and gas become scarcer and more expensive, coal will play an ever-increasing role in the energy future of the United States. Current levels of coal utilization, however, have given rise to an array of problems and issues, and an increase in coal use surely will bring increased attention to those concerns. Many factors come into play in considering how much of the large resource base may ever be available. A very large percentage of the total resource will never be used because of a variety of economic and technical limits and legal restrictions. Coal quality is an especially important limiting factor on coal use.

Coal is, in many ways, a difficult fuel to use. Its mining disturbs the environment. Its transport is expensive and often adversely affects communities along transport routes. Much of the coal burned by utilities must be cleaned before burning; the flue gases commonly must be scrubbed of sulfur and other noxious components after burning. Even with such treatments, applied at considerable cost, coal combustion remains a major contributor to air pollution and acid rain. Waste materials resulting from coal combustion and the spoil piles and disrupted ground of coal mines are sources of noxious chemical elements that may be mobilized by rainwater leaching to contaminate surface and ground water.

A wide range of environmental problems associated with coal mining and utilization is shown in figure 20. Many of these problems are regulated at State and Federal levels, and many represent economic and technological impediments to full utilization of coal resources. Another coal issue concerns the vast amounts of coal on Federal lands and the appropriate use of those lands and resources.

Given the unavoidable concerns that accompany the benefits of America's coal riches and the plans to expand the role of coal, comprehensive geologic information is needed about the wide variability of these resources. Such information includes the amounts and locations of various types of coals, their suitability for different extraction methods and uses, and their accessibility to mining or in-place uses such as gasification or liquefaction. Knowledge of the physical character, chemistry, and mineralogy of coal is needed to gauge the potential for, and to determine how to deal with, environmental or technological problems associated with coal extraction and use. Such information will help improve technologies of coal mining, cleaning and burning, and synthetic fuel conversion and will provide an informed basis for the policy and economic decisions that inevitably will be required by increased coal usage.

COAL RESOURCES AND RESERVES IN NATIONAL PERSPECTIVE

Current annual U.S. production of coal is about 890 million tons. About 85 percent of this coal is used by utilities to generate electricity, and coal provides about 58 percent of the Nation's electricity. Projections of growth in markets for coal tend to focus on electricity generation and suggest that, by 1995, coal consumption in the United States will be about 1 billion tons per year (U.S. Department of Energy/Energy Information Administration, 1986). These projections are greatly affected by the course of oil and gas prices and availability and by the future of nuclear power, and they typically do not include much use of coal for either synthetic fuels or petrochemicals, although some demand in these areas could develop quickly if petroleum availability were curtailed.

In any case, current domestic coal usage is very small in comparison with amounts usually quoted for domestic coal resources. In 1974, the USGS estimated the coal resources of the conterminous United States, in beds thicker than 14 inches and at depths shallower than 6,000 feet, to be about 4 trillion tons (Averitt, 1975, p. 1). (Coal resource data for Alaska are incomplete, but rough calculations indicate that Alaska's coal resources may at least equal those of the conterminous States. Alaskan coal, however, cannot be economically delivered to markets in the conterminous United States, and U.S. coal resources for the foreseeable future generally are assumed to be the 4 trillion tons estimated to exist in the conterminous United States.)

The estimated resource base includes coals from many sedimentary basins across the United States (fig. 21). These coals vary considerably in heat content, quality factors such as sulfur, nitrogen, and ash content, and accessibility factors such as depth, thickness, land use restrictions, and distance from markets. But, before the effects of these variations are considered, it is important to understand what is included in the 4-trillion-ton estimate of potential resources.

Figure 22 illustrates the various components of the estimated total coal resource and shows what parts of the resource are likely to be excluded from practical consideration. For example, less than half of the estimated coal resource (1.8 trillion tons) of 1974 is considered **identified**—that is, relatively certain to occur on the basis of mapping, drilling, and relatively limited extrapolation beyond points of data. The other, larger part of the estimated resource is considered **hypothetical**—that is, projected across basins at depth, far beyond points of data, on the basis of geologic reasoning about regional geology and probable favorable conditions for the occurrence of coal.

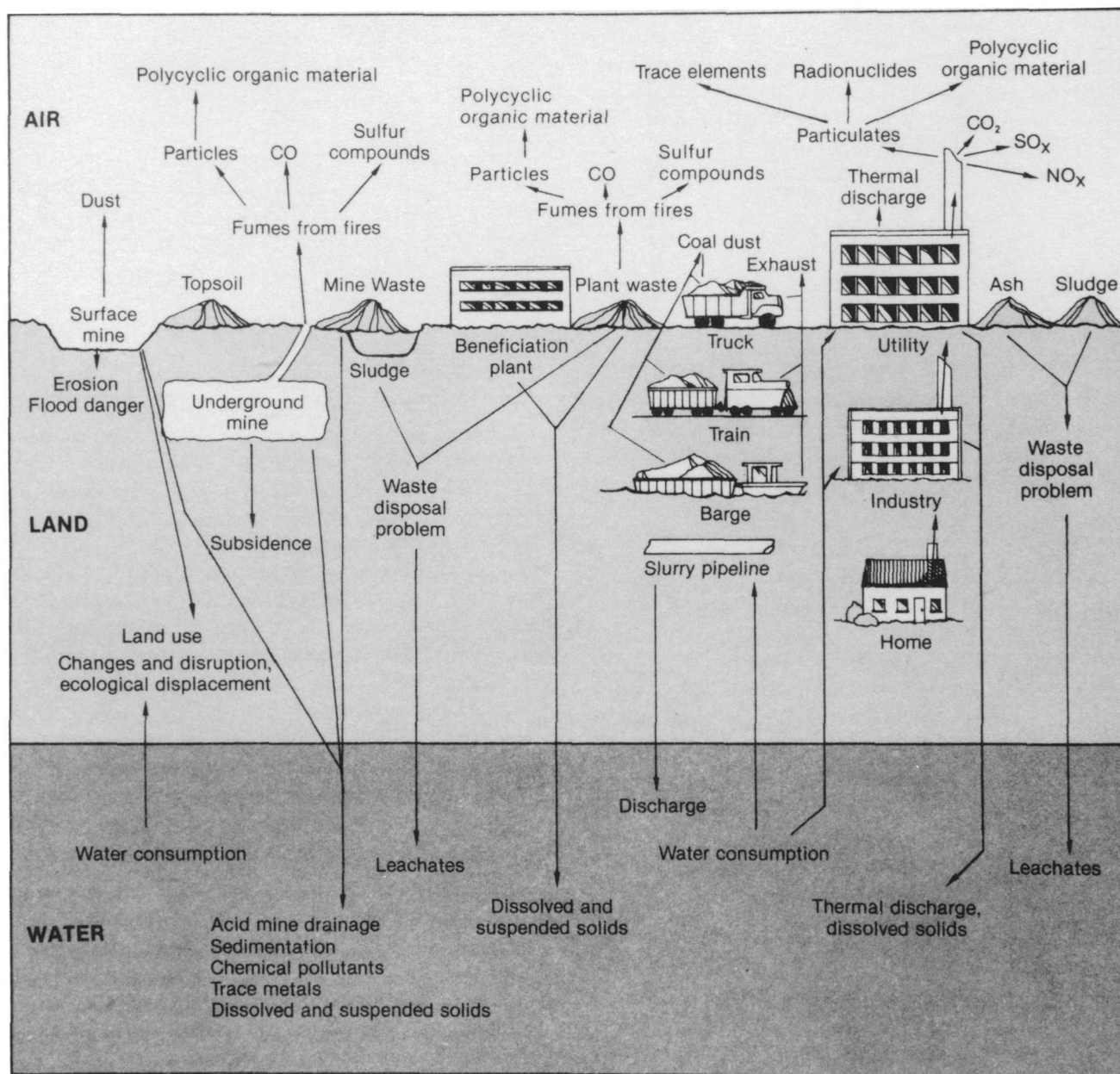


Figure 20. Environmental disturbances resulting from coal-related activities. From Office of Technology Assessment (1979).

The identified resource is further divided into a larger **inferred** category and a smaller **demonstrated** category. The inferred portion is loosely constrained by geologic observations and involves extrapolation techniques that vary from geologist to geologist and according to custom from State to State. The demonstrated portion also is poorly controlled because of nonspecific definitions used in earlier studies and because, from State to State, the boundary between demonstrated and inferred coal is variously 0.25 to 2.0 miles from actual data points.

Some coals included in the demonstrated resource are too shallow, too deep, too thin, or too thick to be

mined effectively and economically. Coal mined or lost in mining is removed next from the remaining coal resource, and the resource is then further reduced by 20 percent to account for restrictions on land use or mining. This reduction factor, however, may be too low. An inventory of surface development and other restrictions for a small area of western Kentucky indicates that 20 percent of the coal land is off limits to mining. In the Powder River basin of Wyoming, various restrictions currently reduce coal availability by about 16 percent, but economic projections indicate that, in the future, only about 50 percent of the available coal will actually be available as the result of

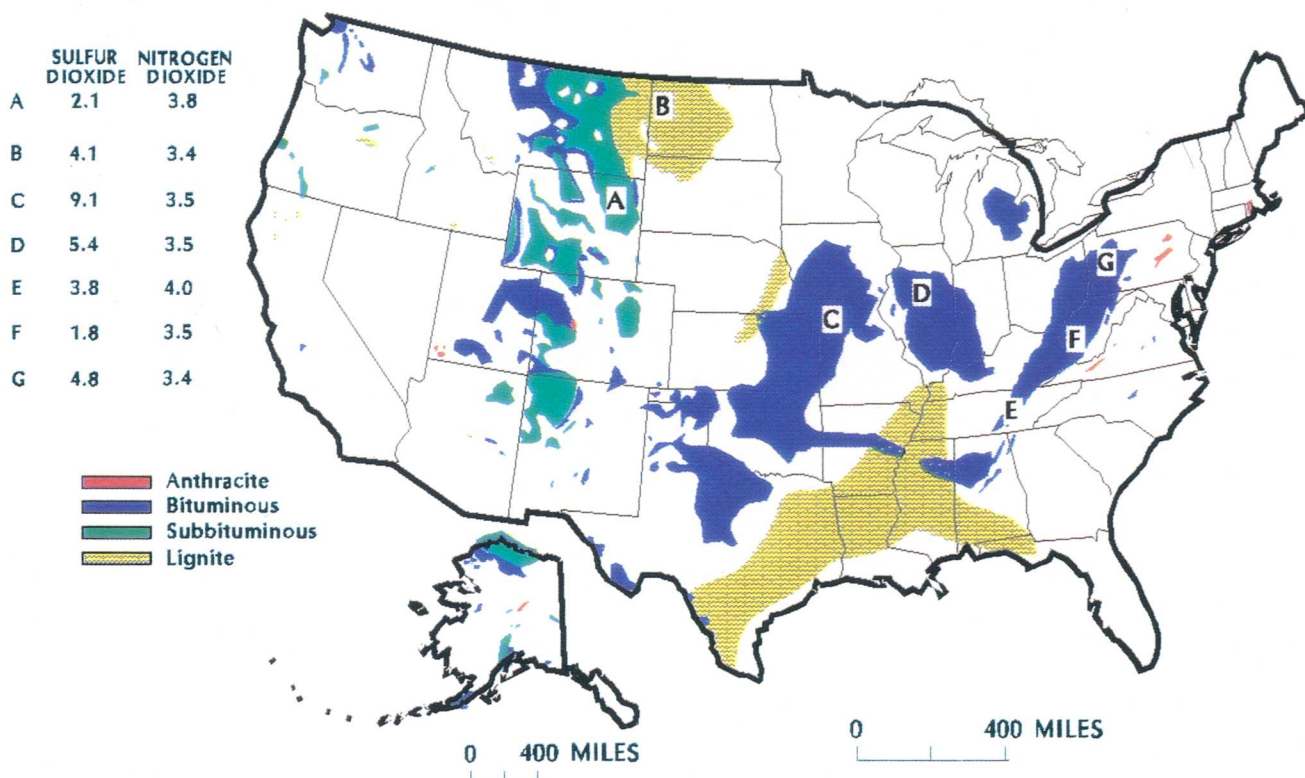


Figure 21. Coal fields of the United States and nitrogen dioxide and sulfur dioxide emissions (in pounds per million Btu) for coal from some of these fields. Modified from M.D. Carter (written communication, 1986) and J.H. Medlin and F.O. Simon (written communication, 1986).

restrictions (see *Focus*, "Regional availability and economics of coal," p. 44). Finally, as much as 50 percent of the coal left in the estimate may be lost in future mining, depending on the kind of mining.

The net result of all these restrictions and reductions is that possibly less than one-twentieth of the 4 trillion tons of coal originally estimated as conterminous U.S. resources may actually be available for commercial production (fig. 22). Of course, many billions of tons of additional usable coal may exist in the inferred and hypothetical categories, but these amounts are not known. On the other hand, heat content, quality factors, and locations of different coals relative to markets have not yet been considered in this discussion, and they certainly reduce the overall amount of coal economically available and usable at the present time.

A closer look at coal availability begins with the recognition that the right kind of coal is not necessarily in the right place. For example, although the use of low-sulfur coal can reduce the sulfur oxide (SO_2) emissions from powerplants that contribute to acid rain, the principal known resources of low-sulfur coal are in the Powder River basin of Wyoming, far from the major markets of the Eastern United States. In addition to transportation costs, the use of western coal in eastern markets requires

paying a heat (Btu) premium, because western coals generally are of low rank (subbituminous) and contain only about two-thirds to three-quarters of the heat value of eastern coals. In terms of average sulfur content, very few basins in the United States contain coal that complies with government regulations on coal burning (fig. 23), at least without expensive precombustion or postcombustion treatment. If concerns about clean air result in further tightening of SO_2 emission standards, no significant amount of coal will be available in the United States that can be burned without treatment.

In areas long associated with coal mining, the resources that actually will be available (that is, the minable reserves) may be much smaller than most investigators had supposed. Much of the original coal resource in these areas has already been mined or lost in mining, and much of the remaining coal is not suitable for mining or marketing or has surface developments or restrictions that preclude mining. The *Focus* section on a well-known source of low-sulfur coal in eastern Kentucky (p. 36) suggests that only about one-eighth of the original coal resource remains as recoverable reserves for future mining. Because of the growing realization that there are limits on coal recoverability, the emphasis in USGS and State coal programs is shifting from collecting data on

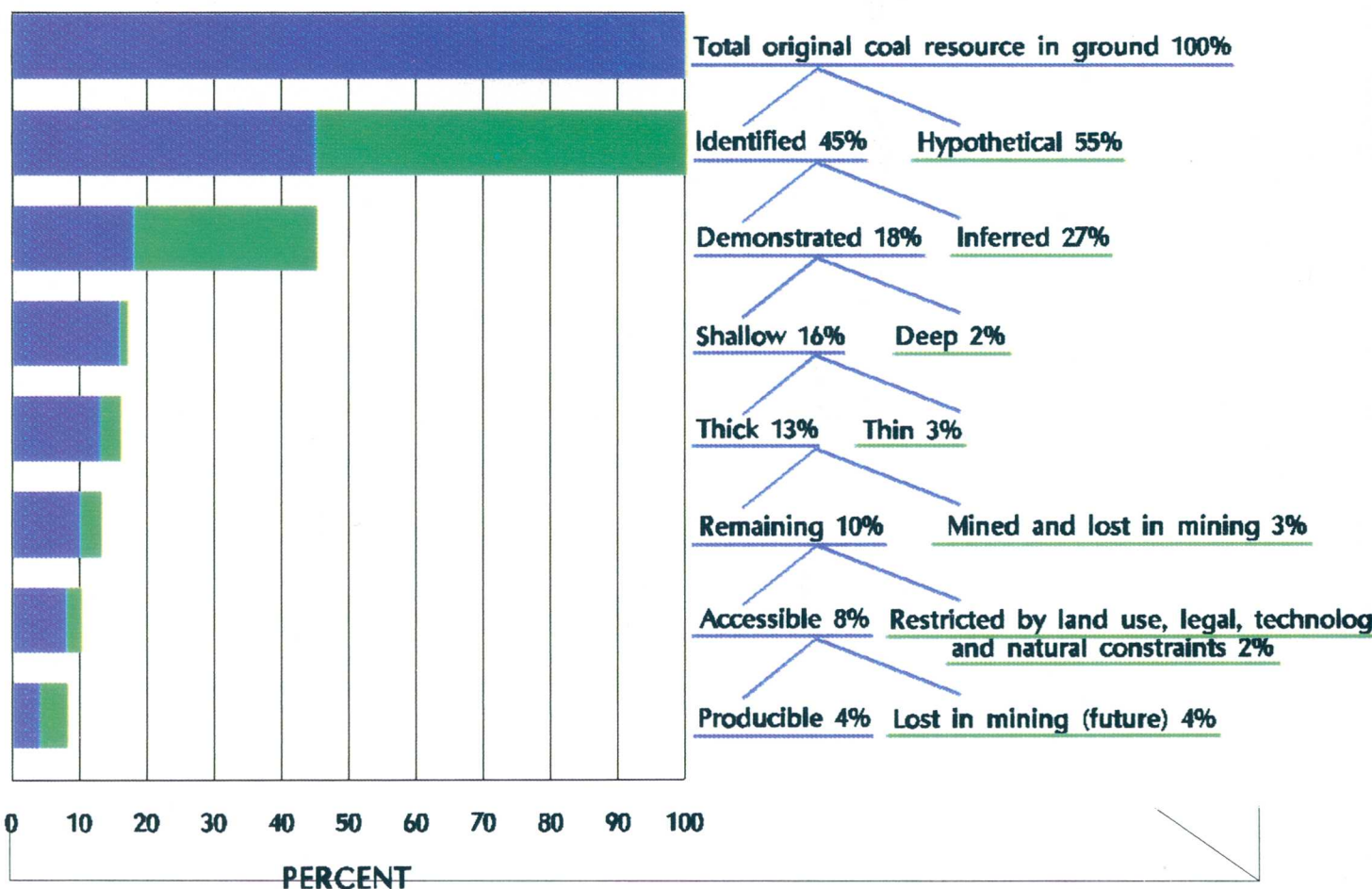


Figure 22. Components of the estimated coal resource of the United States. Modified from M.D. Carter (written communication, 1986).

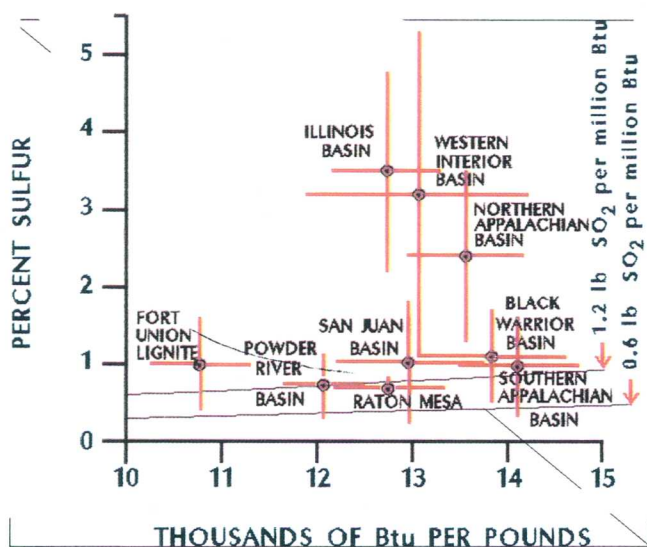


Figure 23. Very few coal-bearing areas in the United States are likely to contain large quantities of coal that will meet either new-source performance standards (NSPS) or revised new-source performance standards (RNSPS) for sulfur emissions without some utilization modification. SO₂ emissions are limited to 1.2 pounds per million Btu (NSPS), and a 90-percent reduction in potential emissions is required except when emissions are less than 0.6 pound per million Btu; in this case, a 70-percent reduction in potential emissions is required. Solid circles represent average sulfur and Btu values for coal from major coal-bearing regions; bars represent one standard deviation about these values. Analytical data are for whole coal samples, as received at the testing laboratory directly from the mine. Modified from F.T. Dulong (written communication, 1985). Source performance standards from Environmental Protection Agency (1979).

resources to categorizing reserves—that is, inventorying the coal likely to be accessible for recovery and categorizing this coal in terms of its probable suitability for various end uses.

The accessibility of coal for underground mining and the ultimate recoverable amount may be limited if more than one coal bed occurs in an area. In such situations, coal extraction commonly is restricted because mining one bed tends to render the beds above or below unminable. Both the collapse of rock above the mined bed and the uneven distribution of overburden weight through the mined bed to underlying beds can result in the effective loss of large resources of coal. In areas where underground mining has occurred in shallow beds beneath relatively weak overburden rocks, collapse of rocks overlying the coal bed eventually may extend to the surface. This collapse produces significant disruption of land and hazards to life and property, including underground mine fires. The Focus section on coal mine subsidence hazards (p. 42) describes problems related to subsidence, including mine fires, and notes the geologic factors that may be involved in choosing between underground and strip mining.

COAL QUALITY AS A POLICY AND ECONOMIC ISSUE

Beyond all the factors described so far, coal quality is and will remain the principal constraint on coal utilization. Coal quality is defined as the combination of various characteristics that contribute to heat content, sulfur oxide and other emissions levels, problems with combustion and waste-product handling, and many other factors. It affects how coal can be used—that is, directly by burning, in mixtures with other fuels, or by conversion to synthetic fuels or petrochemicals.

The quality aspects of coal place coal combustion at the center of national policy concerns about air pollution and acid rain. Policymakers, economists, and scientists disagree greatly about the specific causes, distribution, and extent of problems produced by coal burning and the most effective strategies to mitigate adverse effects of coal burning. Better information on both coal itself and the effects of its burning is needed to properly address these problems, problems that will only broaden as coal use increases. For example, if sulfur and nitrogen oxide emissions were adequately controlled and coal usage thus increased, the amounts of other noxious components in coal such as arsenic, lead, fluorine, and chlorine might reach harmful levels of concentration in the environment. In addition, removing pollutants from one medium (air) through flue gas desulfurization and transferring them to other media (solid waste and water) simply create other problems. If sulfur and other undesirable chemical elements are disposed of with the coal ash, then water percolating through the waste solids may be acidified and

may mobilize pollutants into the environment. Contaminants in scrubber sludge also may create disposal and ground-water problems.

At the practical level of efficient and economical coal use, the physical, chemical, and mineralogical characteristics of coal are critical factors, whether the coal is burned or converted to other hydrocarbon forms. Coal is a complex and heterogeneous mixture of organic and inorganic constituents, and the composition of this mixture varies significantly between regions with regard, for example, to rank or sulfur and nitrogen emissions potential (fig. 21). The chemistry and mineralogy of coal also commonly vary over short distances in a single bed and between different coal beds in any given mining locality (fig. 24).

Most coal-fired powerplants are built for a particular “design fuel” of specified physical and chemical characteristics, and characteristics such as the Btu, sulfur, ash, and volatile-matter content and the chemistry and mineralogy of the inorganic fraction are critical in the plant design. For example, switching from a high-Btu coal to a lower Btu coal that contains less sulfur is an obvious, though possibly not economical, way for a utility to meet clean-air standards, but not if the replacement coal does not fit the plant design. In the combustion process, variations in coal properties and differences in burning characteristics can cause major and costly malfunctions in equipment, such as corrosion, slagging, and fouling of boiler tubes, and changes in the volatile content of coal can require changes in flue gas treatment. If the coal must be cleaned to remove sulfur compounds before burning, the cleaning process must be designed according to the properties and mineralogy of the feedstock coal.

Modifying plants to handle different coals or living with the results of undesired coal variations can be economically burdensome. One utility company estimated that better control on sulfur and ash contents of coal could improve boiler availability by 5 percent (about \$1.5 million per year for a 650-megawatt unit). Another utility company calculated that, for each 1-percent increase in coal ash content above the plant design level, plant availability will be reduced by 1 percent. A third company found that an increase in coal ash content from 15 to 20 percent would cost an additional \$2.6 million per year. Recently, a large western mining company encountered an unexpected chemical change in the coal being mined, and the coal could not be shipped to the customer utility; 4 million tons of production reportedly was lost before a new, acceptable reserve was found. Numerous similar examples reflect problems of coal quality variation and indicate the importance of having reliable geologic information on coal in advance of each step of mining, cleaning and sizing, and utilization.

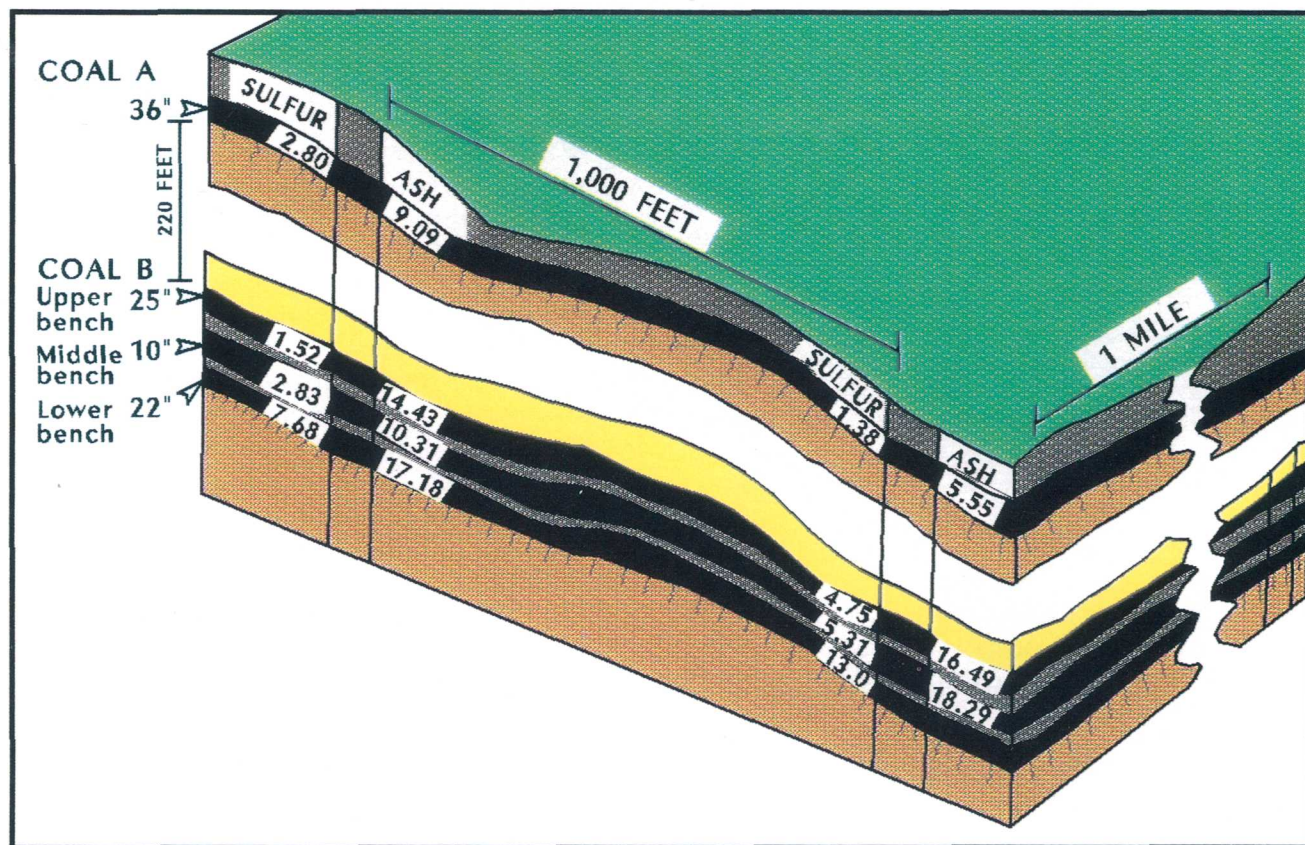


Figure 24. Variability of sulfur and ash contents (in percent) of coal within a single coal bed (coal B) and between coal beds (coals A and B). Vertical lines represent cored drilled holes. Modified from P.C. Lyons (written communication, 1984).

THE ROLE OF GEOLOGIC INFORMATION

Coal is the compressed and altered residue of plants that grow in freshwater or brackish-water swamps. As the plant residues accumulate, they are transformed into peat. Later, during burial by sediments, the residues are altered chemically and physically into coal. Widely varying amounts of sand, silt, and mud are washed into the peat swamps, and this admixed sediment forms the bulk of the ash in burned coal.

The processes active in forming coal, as well as those that affect the coal after it forms, vary according to the environment of the original peat swamp and the subsequent geologic setting of the coal. These variations in processes commonly result in variations in physical character, chemistry, and mineralogy (figs. 21, 24). Modern geologic studies of coal typically attempt to decipher the setting and depositional environment of the original peat deposit, including paleobotanical and paleoclimatic aspects (see *Focus*, "Coal quality and the origins of coal," p. 38), and are fundamental to the characterization of coal reserves in specific areas. The studies also provide a basis for modeling coal-bearing areas to predict the occurrence and quality of coal beyond current exploration boundaries

in an attempt to determine both tomorrow's reserves and the problems that producing those reserves might bring.

Two major gaps in knowledge limit the understanding of coal quality. First, the chemical nature of coal is not well understood, and the processes of coal formation and interactions among various coal constituents need further study. Second, current knowledge is based on a relatively small number of samples from coal beds that either have been mined out or are currently being mined, and few data are available for deeper coals yet to be mined. Figure 25 shows the distribution of sample information for a major Appalachian coal bed and illustrates the problem of coal sampling. Although obtaining samples from a coal bed in advance of mining is both costly and difficult, such samples are required to confirm the ability to predict coal quality on the basis of geologic understanding. As both that understanding and the associated modeling of coal deposits improve, fewer samples will be needed to make reliable predictions about reserves and resources for industry and government planning.

An important component of current studies of coal reserves and resources is the USGS National Coal Resources Data System (NCRDS). This computerized bank of information on coal and its enclosing rocks is the

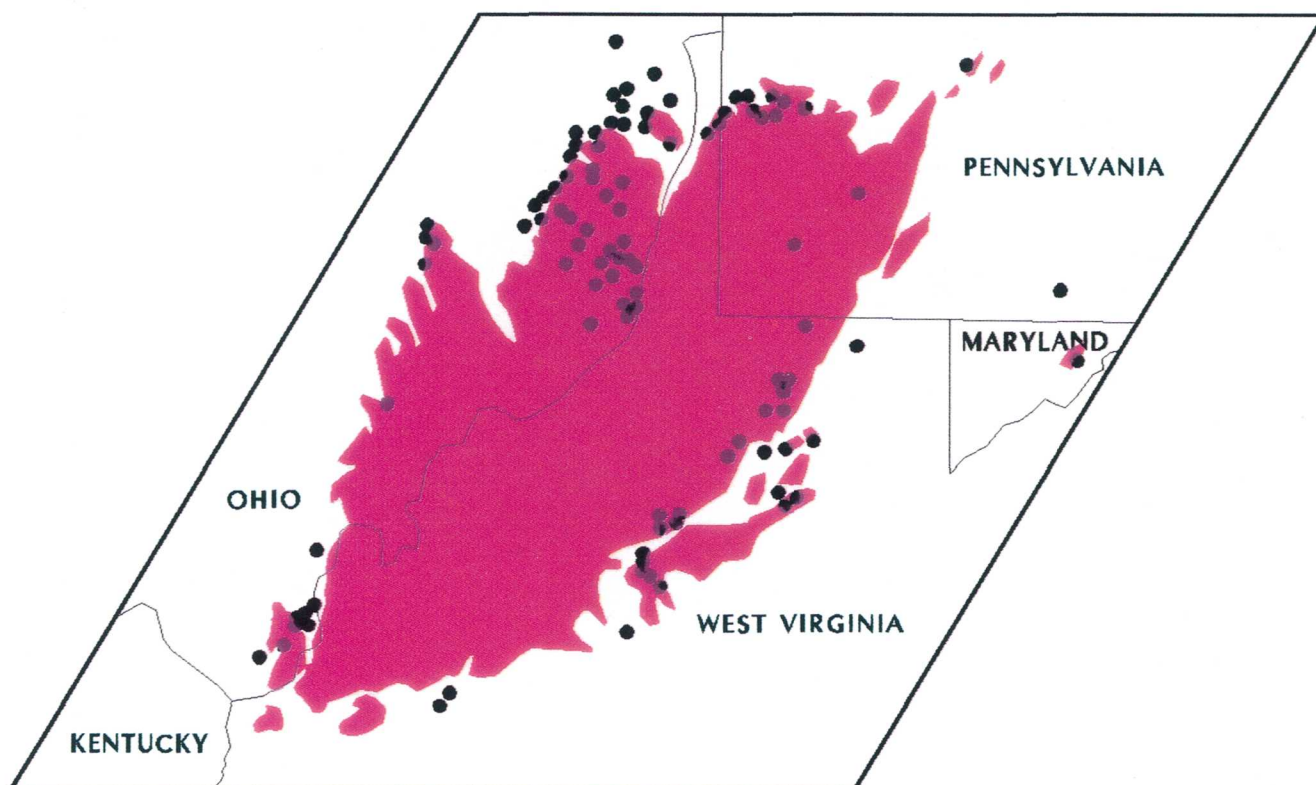


Figure 25. Distribution of sampling information (solid circles) in the Pittsburgh coal bed. Most samples for which data are available are from the edges of the main deposit or from isolated pockets of the main deposit (that is, areas that have been mined out or currently are being mined). Very few, if any, samples are available from the more deeply buried parts of the coal bed. Sample localities shown outside the outline of the coal bed represent very small pockets of the main bed. Modified from J.H. Medlin and F.O. Simon (written communication, 1984).

product of a continuing effort by the USGS and State agencies in 20 coal-producing States. Statistical analysis and mapping routines can be applied to large amounts of data to aid in geologic research and resource assessment. For example, this national data set was used in the discovery of a previously unrecognized and apparently fundamental aspect of sulfur occurrence in coal (see *Focus*, "Sulfur in coal," p. 47). Although the NCRDS data bank and analytical procedures can be readily applied to obtain detailed delineations of area reserves, updated information on the physical and chemical characteristics of coal is needed to support such studies properly.

NATIONAL RESEARCH AGENDA

At a national meeting on coal quality convened by the USGS in 1985, experts from industry, government, and academia developed a proposed national agenda for research on coal quality (Garbini and Schweinfurth, 1986). Cooperative work toward fulfilling this agenda has begun but is in its infancy, considering the scope of the problem and the importance of the subject. Studies of basic coal science and the characterization of coal resources with respect to quality, quantity, and accessibil-

ity could allow development of realistic options for expanded coal use and more reliable prediction of the consequences of such expansion. They could also provide a framework for decisions concerning extraction and preparation methods—that is, whether to clean, blend, crush, or size coal and by what methods—and they can form the basis for planning coal feedstock sources and specifications. The information gained from these studies will undergird efforts to improve technologies for cleaning, burning, and converting coal and perhaps for gasifying or liquefying coal in place.

On the basis of knowledge gained from these studies, regional models of potential sulfur emissions can be constructed for both the short- and the long-term future. Coal deposit and coal accessibility models that include accurate and comprehensive information about coal quality and coal availability could allow formulation of policies and regulations strategically directed toward solving important long-term problems of coal use and avoiding unnecessary or inappropriate restrictions on coal use. The costs of expanding both basic and applied research on coal are small in comparison with the costs of technologic mistakes or of promulgating and enforcing regulations that fail to resolve problems surrounding coal use.

Focus: Coal Resource and Reserve Characterization in Eastern Kentucky

The Eastern Kentucky coal field is one of the most productive coal-producing areas in the United States and probably in the world. It produces one-sixth of the coal mined in the United States and contains one-half of the operating coal mines. Coal has been mined in eastern Kentucky for 200 years, and 7.5 billion tons of coal has been either mined or lost in mining. Although the remaining resources of the field are estimated at 56.6 billion tons, some authorities believe that as few as 10 billion tons of economically recoverable coal remain.

Kentucky's legacy as one of the foremost coal-producing States has produced a culture, infrastructure, and business climate favorable to coal mining that paradoxically now poses a threat to future mining. Many of Kentucky's remaining resources are adjacent, superjacent, or subjacent to mined-out areas, and both government mining regulations and mining engineering practices preclude the mining of coal too close to existing mines. Although no attempt has been made to assess the impact of past mining on future potential, the extent of past mining suggests that the amount of affected coal is quite large.

In 1983, the Kentucky Geological Survey completed an assessment of Kentucky's coal resources. Considerable effort was spent mapping the thickness and extent of each coal bed, quantifying resources by thickness, and qualifying the estimates on the basis of distances from actual coal measurements. Approximately 25,000 coal thickness measurements were computerized for easy plotting and calculation of resources; this work was partly supported by the USGS. The data base was used to prepare 3,500 coal maps for 40 coal beds and coal bed splits thicker than 14 inches. Resource reports for six coal resource districts have been published, and the supporting data are being published.

The remaining resources of the field were estimated by subtracting the total coal mined times two from the original resource. The total coal mined times two roughly approximates the sum of coal actually mined and coal left in the ground as pillars or lost in cleaning and represents the commonly accepted recovery factor of 50 percent. Many factors important to understanding the fuel supply potential of these resources were not considered, including overburden ratio, depth, quality, and minability, which includes factors such as coal bed continuity, dip and splitting of the bed, and roof and floor quality. Consequently, the estimate of remaining coal resources in the Eastern Kentucky coal field includes large amounts of coal currently not economically or legally minable. The estimate of 56.6 billion tons for remaining resources in the field is overly optimistic and potentially misleading

without appropriate qualifications, and research has begun to characterize remaining reserves.

Maps of mined-out areas that were made by coal-mining companies are now being used to refine the Kentucky Geological Survey's coal resource maps. The locations of mined-out areas, legal easements for roads, towns and certain designated public lands, and oil and gas wells (near which mining cannot occur) are overlaid on coal resource maps. After remaining resources have been limited to coal that is legally accessible, modern mining and economic criteria can be applied to estimate the remaining reserves according to specified costs. Studies of test sites in the Eastern Kentucky coal field are expected to allow extrapolation of reserve estimates to the entire coal field and perhaps to parts of West Virginia, Virginia, and Tennessee. Preliminary results from an area of Pike County, Kentucky, indicate that about 250 million tons, or 31 percent, of the original resource in one major coal bed has been mined or lost in mining, and as much as 350 million tons, or 44 percent, may not be accessible because of interference resulting from prior mining and various physical and legal obstacles to future mining (fig. 26, table 1). Only about 25 percent of the original 800 million tons in place remains as minable reserves, and only a little more than one-half of that amount has a high probabil-

Table 1. Preliminary remaining coal reserve characterization in an area of Pike County, Kentucky
[Reserve characterization map shown in figure 26]

	Amount of coal, in millions of short tons
Estimated original resources-----	800
Mined out and lost in mining-----	-250
Geologic constraints----- (high ash content, cutouts, bad roof, too thin).	-150
Legal constraints-----	-50
Interference----- (mine barriers, ownership patterns, oil and gas wells).	-150
Estimated remaining reserves in ground-----	200
"Surface" recovery factor----- (80 percent on 50 million tons).	-40
"Underground" recovery factor----- (50 percent on 150 million tons).	-75
Estimated remaining potentially recoverable reserves ¹ -----	115

¹ Not all potentially recoverable resources are economically minable. The ultimate decision to mine depends on factors such as ash fusion, chlorine content, location of transportation systems and cleaning facilities, and others not considered in this analysis.

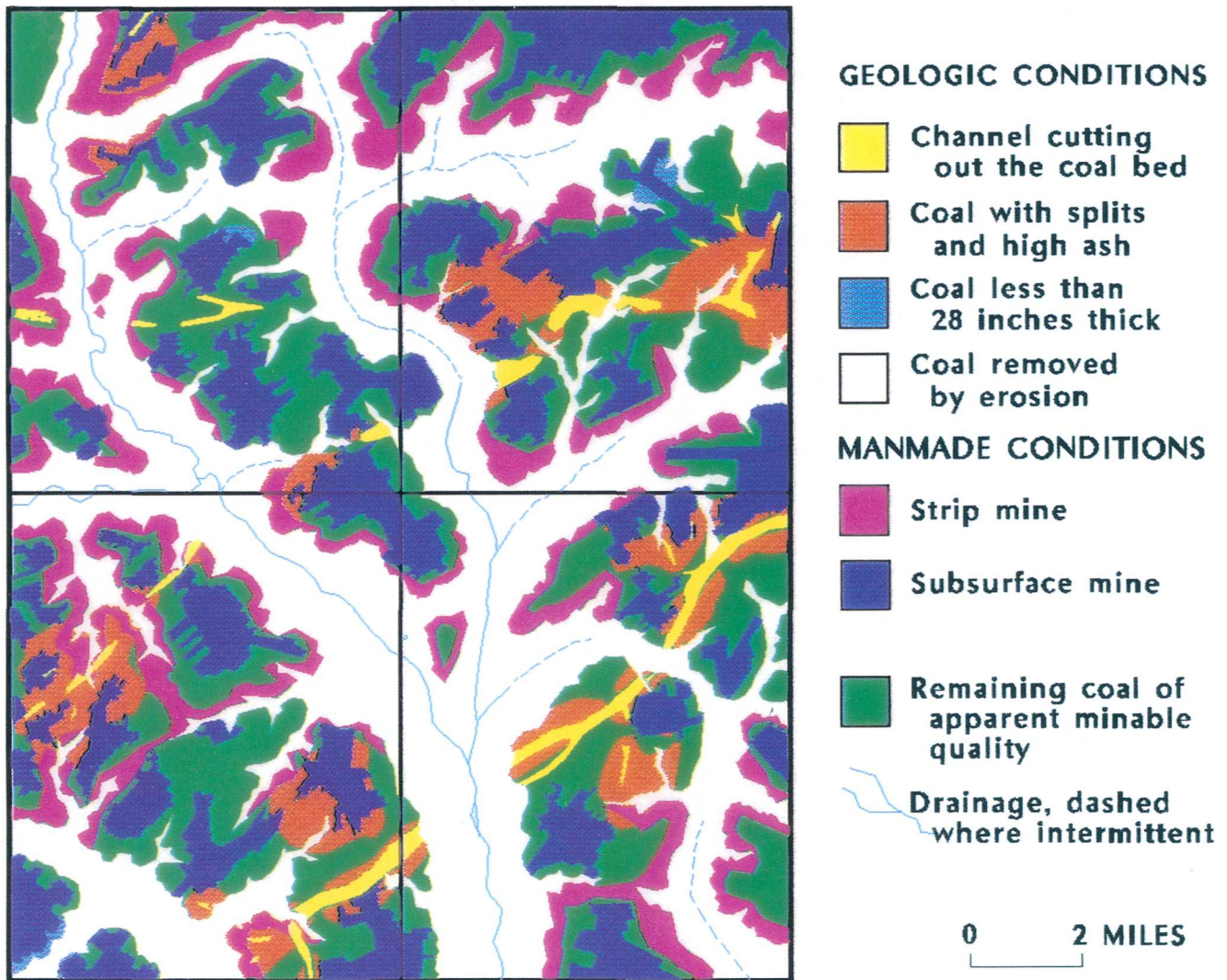


Figure 26. Various factors, both geologic and man induced, affect the future minability or extraction of coal resources. This map of a small area in Pike County, Kentucky, uses representative measurements from the county to show how these factors combine to severely limit the amount of coal suitable for mining.

ity of being recovered. Other economic, engineering, coal quality, land ownership, and environmental factors will determine what ultimately will be produced.

Research has just begun to characterize the remaining coal reserves of the Eastern Kentucky coal field and to assess the impact of past mining, legal restrictions, oil and gas wells, geologic obstacles, and

mining engineering and economic criteria. Because many of the Nation's energy, electricity generation, mining, transportation, and State government plans are based on the assumed availability of economically minable coal, a characterization of the remaining reserves as either fact or wishful thinking is fundamental toward informed consideration of both plans and policy.

Focus: Coal Quality and the Origins of Coal

Variations in coal quality result from the chemistry of the peat-forming environment, interactions among local sedimentary processes during peat formation, and chemical changes that occur after burial. Variations in coal quality have been documented in a detailed study (Stanton and others, 1986) of the Upper Freeport coal bed (Pennsylvanian age) in mines near Homer City, Pa., and a companion study of two coal beds in the Powder River basin of Wyoming.

The study of the Upper Freeport coal bed was done cooperatively by the USGS, the Environmental Protection Agency, the Pennsylvania Electric Corporation, and the New York State Electric and Gas Corporation. The entire block of coal reserves in these mines was studied with the aim of identifying and then predicting changes in coal quality, so that mining plans might be designed to minimize quality variations in the coal product delivered to powerplants.

The Upper Freeport coal bed contains discrete coal zones, or facies, that are characterized by distinctive associations and concentrations of compressed plant materials (macerals) and minerals. These coal bed facies were mapped over an area of 120 square miles in west-central Pennsylvania. Where the coal bed is thickest, it averages 83 inches and contains 8 to 10 facies; in other areas, the bed averages about 48 inches and generally is composed of 4 facies. Figure 27 shows a schematic three-dimensional view of part of the coal bed. Once the coal facies were identified, they could be traced throughout the coal reserve. Zones of sandstone that developed during the peat-forming stage also were identified and their distribution predicted. The amount of ash-forming minerals in the coal bed increases substantially near these sandstone zones, the result being areas that should be avoided in mining. Other quality parameters, such as sulfur content, were found to be associated with individual coal facies, which have specific coal washability characteristics.

Areal distribution patterns of ash and sulfur for each coal bed facies indicate different physical and biochemical conditions during peat formation that affected both the type and amount of plant materials and minerals. Three sets of conditions were inferred for the origin of different coal bed facies of the Upper Freeport coal, consistent with interpretations of modern peat formation based on the interaction of climate, plant types, rainfall, ground-water chemistry, nutrient supply, and sedimentation. The resulting conceptual model provides a means to evaluate and predict more precisely, in advance of mining, the variability of coal resource or reserve quality.

Depositional controls on peat-forming environments that produce thick (greater than 30 feet) coal beds

can be inferred from relationships among coal bed geometry, organic material composition, and associated rock types. A study of these relationships within sedimentary sequences associated with the Wyodak-Anderson (Paleocene age) and the Felix (Eocene age) subbituminous coal beds in the Powder River basin of Wyoming suggests two modes of peat accumulation, both of which are controlled by patterns of stream movement and sediment deposition by streams in swamp areas. The Wyodak-Anderson peat is interpreted to have formed in restricted parts of a flood plain that were separated from one another by channels of a braided stream. The channels and associated sediments maintained their positions through time because they were confined by thick deposits of raised or domed Wyodak-Anderson peat. In contrast, the Felix coal bed is interpreted to have formed as a raised but widespread peat on an abandoned platform of sands deposited by a meandering stream (fig. 28).

Other studies of coal quality by the USGS in cooperation with State surveys are producing new, practical results. Data from reconnaissance sampling of coal beds and rocks throughout the main coal-bearing geologic sequence of the central Appalachians show a distinctive pattern of ash and sulfur contents from the lowest to the highest coal beds in the sequence (fig. 29, table 2). Coal beds in the lower, or older, part of the sequence typically are low in sulfur and ash, whereas coal beds in the upper, or younger, part are high in sulfur and ash. This variation in coal chemistry with time is interpreted to be related to changing climate and conditions (or setting) of peat accumulation in swamps. The upper coal beds are impure and of relatively lower quality because their

Table 2. Characteristics of paleopeat formation and coal quality in coal beds in the central Appalachian basin [Modified from Cecil and others (1985, p. 218)]

Pennsylvanian-Permian(?) formation (series)		
	Kanawha New River Pocahontas	Dunkard Monongahela Conemaugh Charleston/ Allegheny
Paleoclimate-----	Ever-wet tropical.	Seasonal tropical.
Paleopeat formation-----	Rainwater water source.	Surface and ground water.
Spatial form of-----	Domed paleopeat deposits.	Planar
Coal quality-----	Low ash, low sulfur.	High ash, high sulfur.

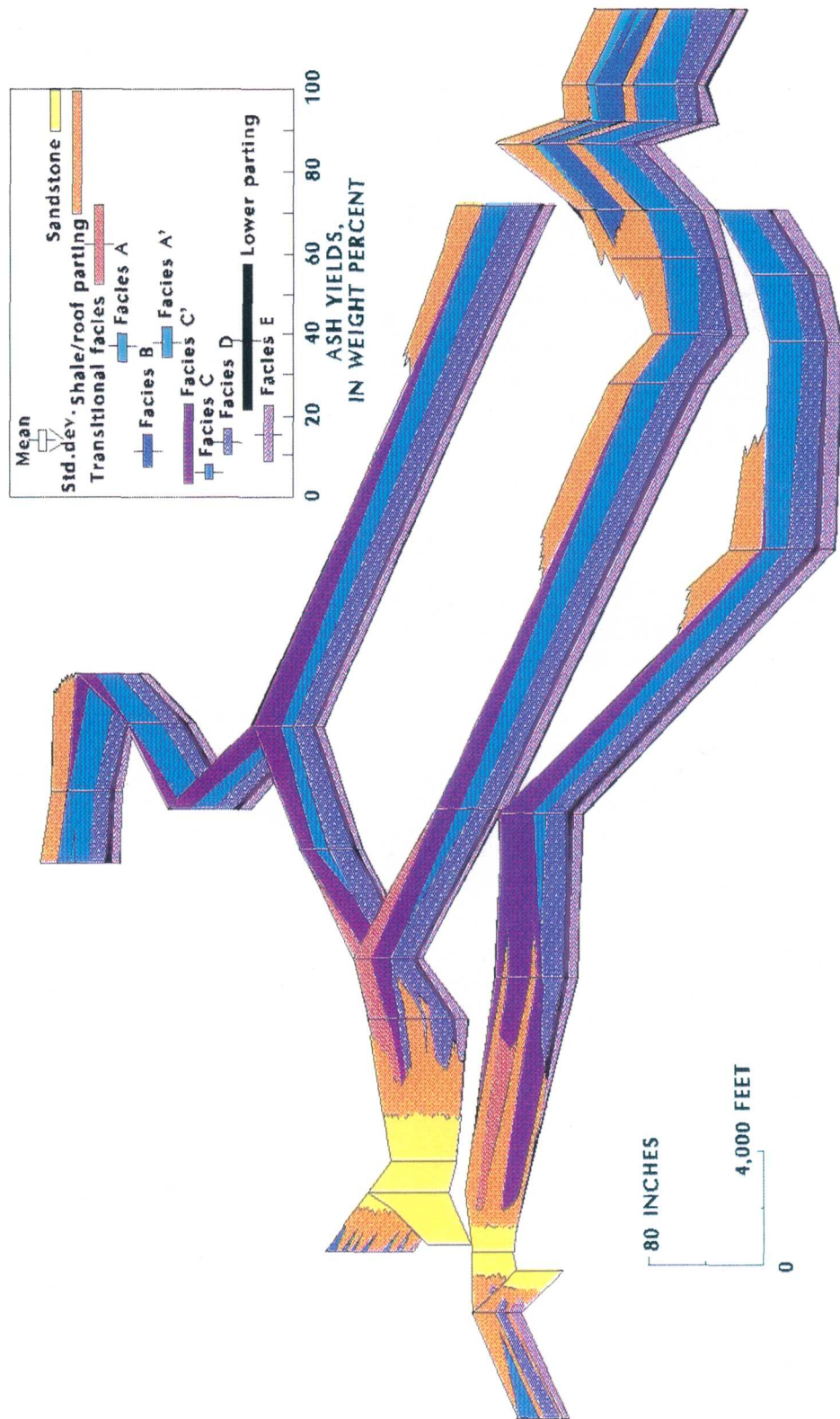


Figure 27. Coal bed facies in the Upper Freeport coal bed. Modified from Stanton and others (1986, fig. 3).

FELIX COAL BED

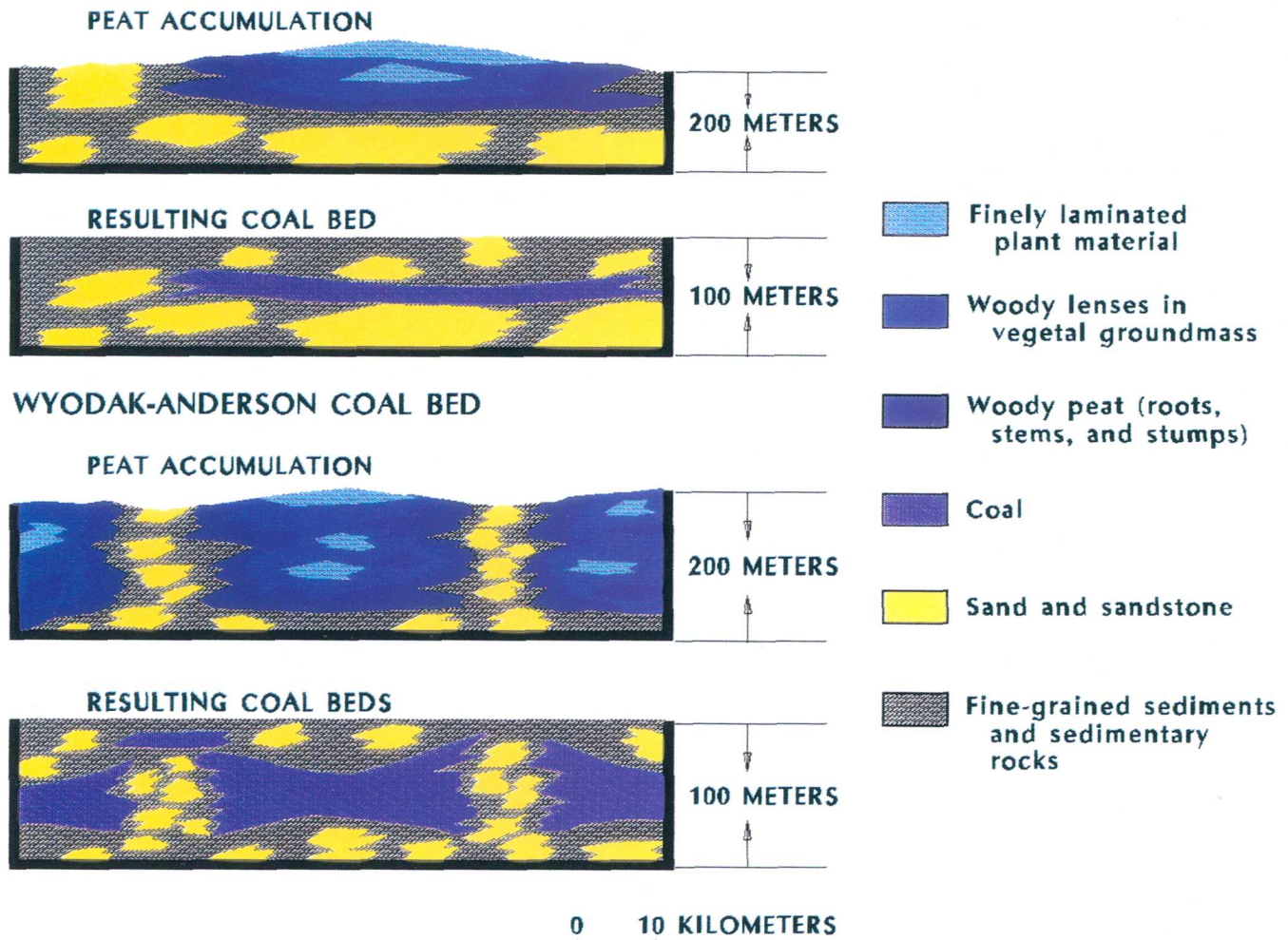


Figure 28. Environments of deposition of coal of the Felix and Wyodak-Anderson subbituminous coal beds. Modified from P.D. Warwick and R.W. Stanton (written communication, 1987).

precursor peat formed in swamps fed by chemical-laden ground water and by surface water that contained relatively large amounts of mineral matter. This setting produced dominantly planar peat accumulations accompanied by heterogeneous plant communities. The lower coal beds are cleaner and of higher quality because they formed from domed peat deposits that received mostly rainwater nourishment and little sediment influx. The zoned plant communities that characterize this setting

produce a coal bed facies arrangement different from that formed by planar peat deposits.

Detailed coal quality studies are providing new understanding of the origin and development of coal, so that variations within and between coal beds can be identified, explained, and then extrapolated to make predictions about undrilled areas. The new insights provide a basis for better planning of coal mining, cleaning, and blending to obtain a preferred product.

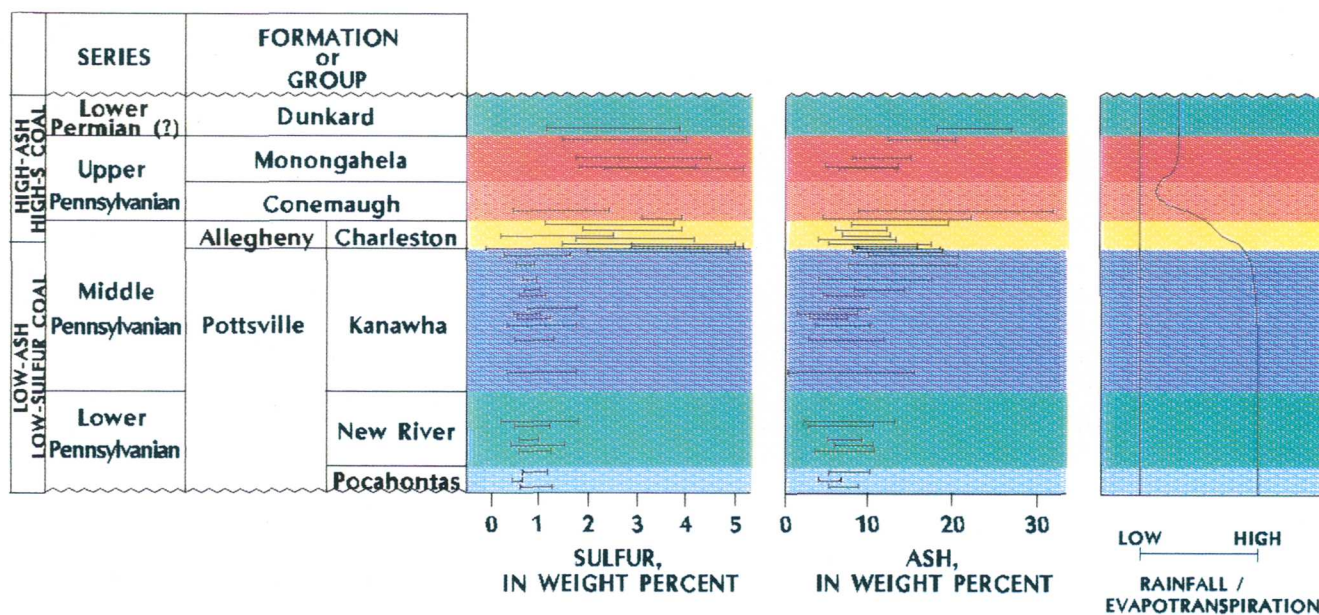


Figure 29. Stratigraphic variations in ash and sulfur contents in coal beds of the central Appalachian basin and the ratio of rainfall to evapotranspiration as interpreted from lithology and coal quality of formations. Data from National Coal Resources Data System. Figure modified from Cecil and others (1985, p. 205, 210, 224).

Focus: Coal Mine Subsidence Hazards

In areas where coal has been mined by underground methods, collapse of mine openings and related coal mine fires can cause serious and expensive hazards long after the mines have been abandoned. In many areas where underground mining was done in the 1800's and early 1900's, unmined coal pillars of variable size and spacing support the overlying rock and soil for decades or even centuries before yielding to cause gradual settling or sudden collapse at the surface.

When mine roofs collapse and the pillars crush or punch into the roof or floor rocks of the mine, depressions and cracks or pits eventually may form at the surface and pose a threat to life and property. The time required for hazards to develop after mining depends on the geologic properties of the rock, the depth of mining, and the method of mining. If most of the coal was removed, the rock commonly subsides gradually in a few

years, but, if pillars remain, pits may form above adjacent mine chambers decades or even centuries after the mines are abandoned.

Subsidence pits are common above abandoned underground mines in areas where the overburden is less than 10 to 15 times the thickness of coal mined (fig. 30). In areas where the caved material is carried away by ground-water flow, surface subsidence can occur at depths greater than 10 to 15 times the mined thickness. Subsidence depressions can occur at any depth above areas from which coal has been completely extracted and in which the minimum width of the mined cavity equals or exceeds the thickness of the overburden.

Subsidence is a nationwide problem. Results of a study by the U.S. Bureau of Mines (Johnson and Miller, 1979) indicate that 7.1 million acres of land has been undermined in 25 States in the conterminous United



Figure 30. Oblique aerial view of pits and troughs that formed by surface subsidence above abandoned coal mines located 6 miles north of Sheridan, Wyo. The mines were operated from the 1890's to the 1920's, and coal was mined from three different beds. In places, the mine workings are stacked above one another. The overburden comprises weak, soft rocks and is 15 to 150 feet thick. Pits and troughs located in draws draining into Goose Creek (near background) disrupt or divert surface water to old mine workings. The Bighorn Mountains are in the far background. From Dunrud and Osterwald (1980).

States, of which 1.9 million acres already has been affected by subsidence. Of the 5.2 million acres of future potential subsidence, approximately 418,000 acres is near populated areas. The 10 States having the greatest areas (in acres) of potential subsidence (on the basis of underground production records) are Pennsylvania (151,000), West Virginia (89,100), Illinois (41,800), Kentucky (37,200), Ohio (21,800), Virginia (13,400), Alabama (11,700), Indiana (10,900), Colorado (6,300), and Tennessee (5,000). The total estimated cost of stabilizing land undermined by abandoned coal mines in the conterminous United States is \$12.5 billion (1978 dollars) (Johnson and Miller, 1979).

In addition to subsidence problems, underground fires can destroy valuable coal resources and cause serious atmospheric pollution. The fires commonly start by spontaneous ignition when water and air enter abandoned mine workings through subsidence cracks or pits; they may start by careless dumping and burning of garbage in subsidence pits. The Bureau of Mines estimates that there are about 260 uncontrolled fires in abandoned mines in some 16 States; these fires threaten 760 million tons of coal and cause local atmospheric pollution and health hazards. The 10 States where the greatest amount of coal (in millions of tons) is threatened by fires in abandoned mines and inactive coal deposits are Montana (220), North Dakota (166), Colorado (100.5), Pennsylvania (91.3), Wyoming (81), Utah (45), Arizona (23), West Virginia (14.6), New Mexico (6.5), and Ohio (4.8).

USGS studies of the surface effects of past underground coal mining near Sheridan, Wyo., and in other areas of the Western United States indicate that underground mining of coal deposits located at strippable

depths eventually may damage the environment more than mining by modern surface methods, provided that proper restoration techniques are followed (Dunrud and Osterwald, 1980). In modern surface mining operations, the total land surface above the minable coal is sequentially removed, and, as the coal is removed, the overburden and topsoil are sequentially replaced and the surface regraded to the original landform and revegetated. Land disturbed by surface mining can be more easily returned to long-term use than can land underlain by shallow abandoned underground mines, and the resource recovery from surface mining typically is much greater than that from even modern underground mining procedures.

Detailed information on topography, geology, hydrology, and mining procedures is needed before existing and future subsidence hazards can be accurately assessed. Engineering geologic studies on the type, strength, and thickness of rocks above abandoned underground mines and a determination of the areal extent of abandoned mines are particularly important. Unfortunately, it is difficult to determine the extent of underground mines abandoned in the 1800's and early 1900's, because mine maps and production records are unavailable or incomplete.

Experiences in populated areas underlain by abandoned underground coal mines—such as the Denver-Boulder metropolitan area and Colorado Springs, Colo.; Scranton, Pa.; Rock Springs, Wyo.; and Des Moines, Iowa—indicate that the time and money spent on site studies and land use planning before surface development are much less than those spent on mitigation procedures after surface development.

Focus: Regional Availability and Economics of Coal

Coal resources are more equally distributed across the United States than other fossil fuel resources are, but coal availability is affected by land access and land use restrictions, the sulfur content of the coal, and mining economics. Efforts to achieve clean-air standards by reducing sulfur emissions from utility plants have increased the demand for low-sulfur coal. High-Btu low-sulfur coal carries a price premium; much of this coal is in the Eastern United States and is extracted by underground mining. Low-Btu low-sulfur coal is abundant in the Western United States and typically is extracted by low-cost open-pit mining, but a significant amount of western coal is inaccessible because of land use restrictions and environmental concerns. Such concerns and the associated regulation of mining are particularly an issue with regard to large coal deposits within or near unique and highly valued natural areas.

The effects of local land use restrictions in important coal resource regions can be examined in relation to national coal distribution patterns and cost effects. A dynamic linear program model of the coal distribution network in the United States (243 demand regions, 100 supply regions, and 5 transportation modes) has been developed by the USGS to estimate extraction, transportation, and sulfur removal costs for coal and to project the market effects of supply restrictions and consumption regulations. The program minimizes the costs of extraction, transportation, and cleaning subject to a set of constraints. For example, shipments cannot exceed supply, delivery must meet demands, sulfur discharges cannot exceed allowable limits, barged shipments cannot exceed waterway capacities, and transmission of minemouth-generated electricity cannot exceed technical engineering limits.

The coal resources of the United States tend to have regional characteristics, such as rank (heat content), sulfur content, and number or continuity of beds. In addition, limiting factors, such as extraction and transportation costs, sulfur emission controls, and land use restrictions, tend to maintain a regional division into eastern, midwestern, and western areas of supply. The linear program was used to model demand and supply for Powder River coal, changes in intensity of Powder River coal use in the same markets over time, and the extent of new market penetration over time. The model is confined to the dominant Powder River coal source, the Wyodak coal bed of Campbell County, Wyoming, in which overburden is less than 200 feet thick and strip mining is feasible. Figure 31 shows projected powerplant use of low-sulfur Powder River coal for the years 1990 and 2015. The model predicts that demand for this coal will expand from 155 million tons in 1990 to 468 million tons in 2015

in the markets served and that use of Powder River coal in midwestern and south-central markets will expand between 1990 and 2015.

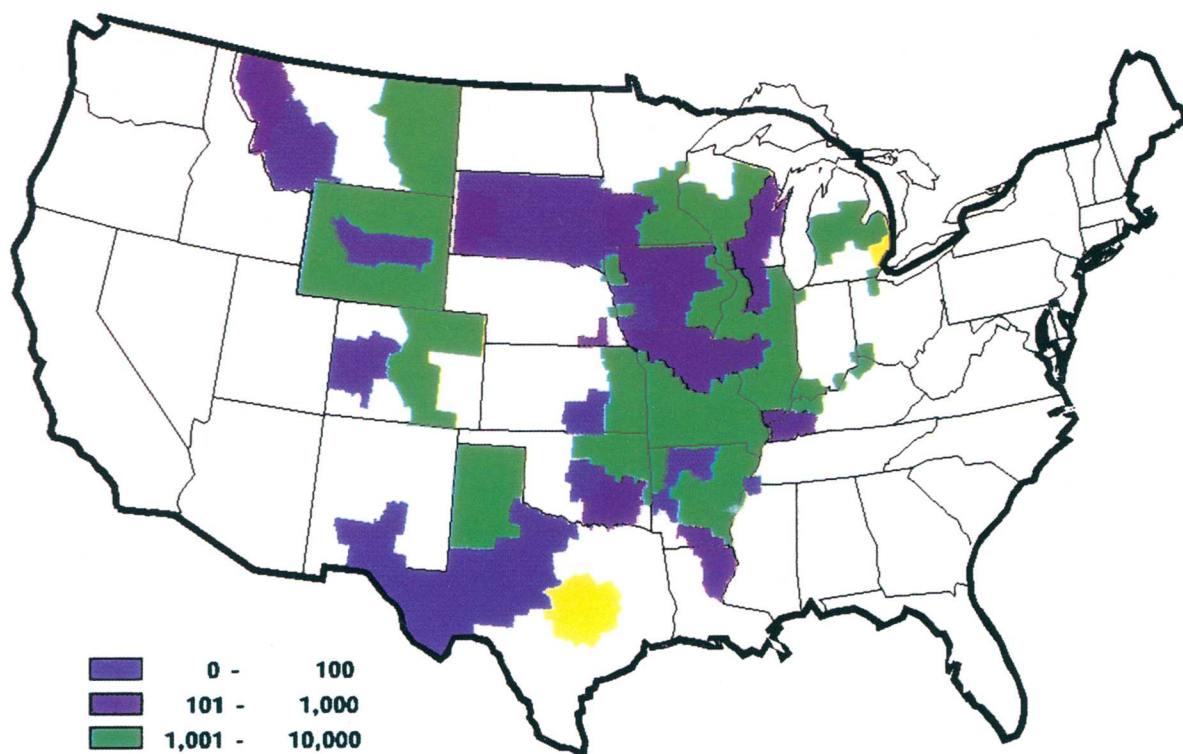
If access to lands suitable for mining is unlimited, the model predicts that, by the year 2030, annual production of strip-mined Powder River coal will be 601 million tons and cumulative production will be 16.4 billion tons. Public land withdrawals and land use restrictions dictate, however, that only part of the coal will be available for future production. Figure 32 illustrates land use restrictions for Campbell County. Although only about one-third of the coal suitable for mining is likely to be legally restricted, a significant amount of the remaining coal is scattered among different owners or fragmented by land use restrictions and will not form logical mining units, or the land may have other uses or values deemed more important. It seems likely that a substantial portion of the potential coal resource of the area will never be exploited.

The effect of restrictions multiplies when it is also considered how much of the accessible coal will be available at different prices. The model has been used to compare cumulative coal production in the Wyodak-Anderson bed in Campbell County well into the next century and at different prices, for cases of both unlimited and limited (by land use restrictions) access. The model predicts that land use restrictions will reduce the available amount of the lowest cost coal by 6 billion tons and the available amount of higher cost coal (as high as \$40 per ton) by almost 20 billion tons. When low-cost production from all of Wyoming is modeled to compare projected output under existing land use restrictions in Campbell County with a hypothetical case in which no land use restrictions are imposed, the difference is remarkable. The model predicts that Wyoming production will increase during the next 40 years but that, if restrictions are imposed, restricted production will begin to differ from unrestricted production after 2005. The difference in production projected to 2025 is more than 400 million tons (about 200 million tons of production with restrictions and 650 million tons without restrictions).

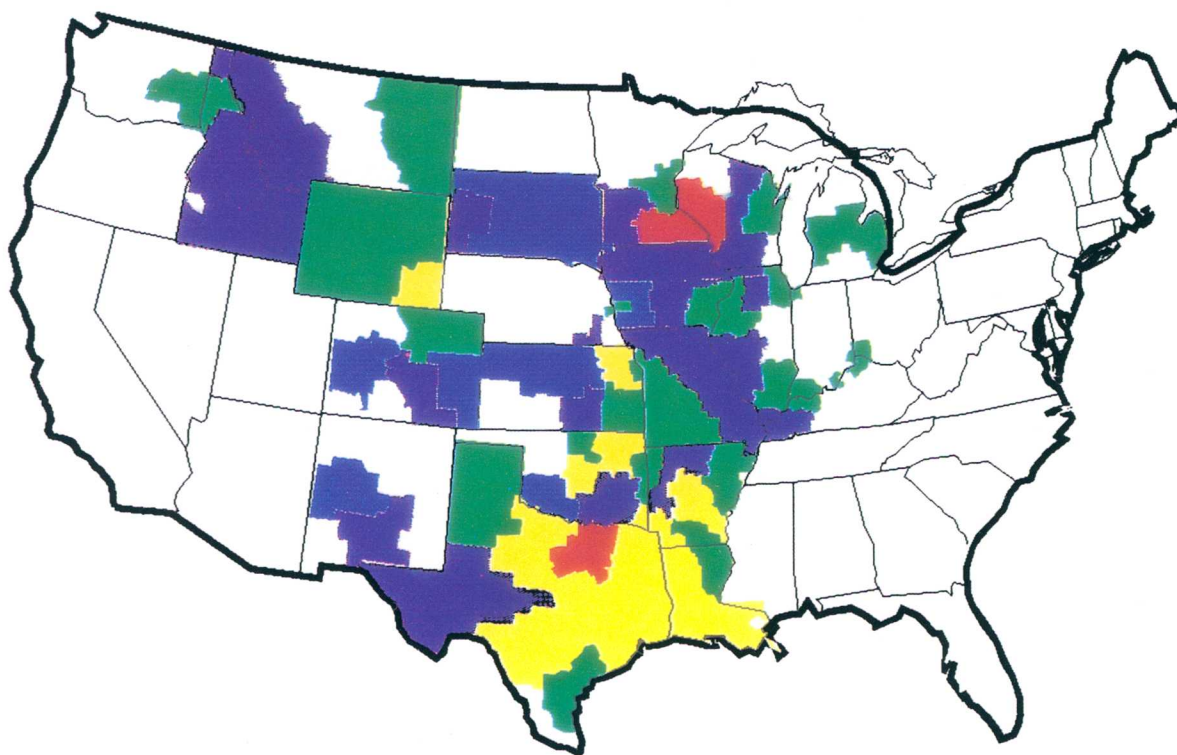
The State of Wyoming, which contains a large amount of Federal land, is a particularly good illustration of land use restrictions. Coal deposits in national parks, wilderness areas, and wildlife refuges cannot be mined, and, under current regulations, coal deposits near such

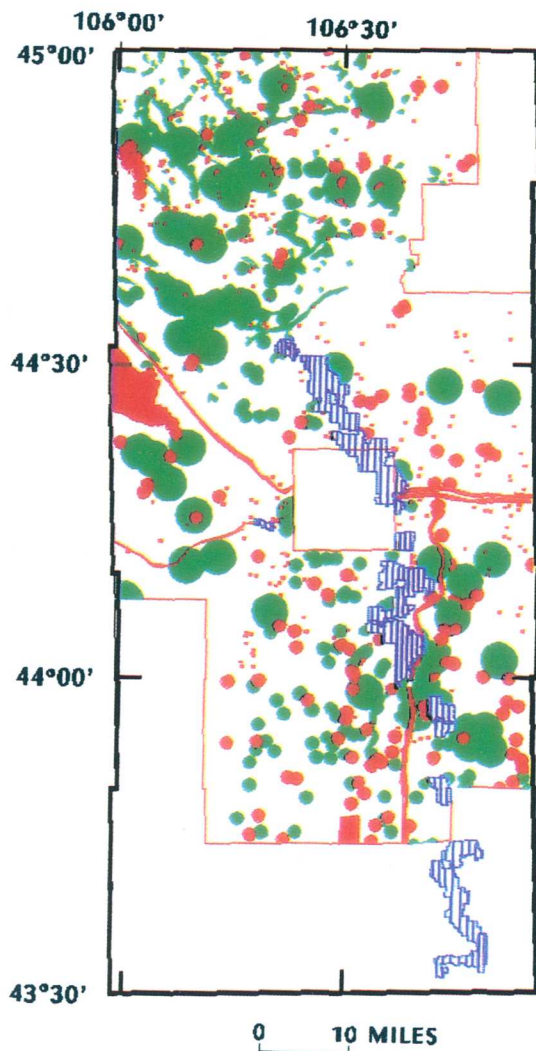
Figure 31. Predicted consumption of low-sulfur Powder River coal for powerplant use will increase from 155 to 468 million tons between 1990 (A) and 2015 (B) and use of Powder River coal in midwestern and south-central markets will increase. ►

A



B





restricted areas may never be mined. The model approach described shows that the economic effects of local land use restrictions reach into markets across the country and significantly change resource availability through time. Many types of restrictions, both regulatory and economic, apply to coal resources throughout the United States. The overall effect of land use restrictions on production is not now great but will increasingly influence production, price, and breadth of markets over the next 10 to 50 years in all parts of the United States. Other restrictions, such as stricter clean-air standards, will have greater and more immediate effects and can also be modeled to predict their ramifications.

◀ **Figure 32.** Land use restrictions and unsuitability for mining, Campbell County, Wyoming. Red indicates areas in which coal development is restricted by competing land uses; green indicates areas in which coal development is acceptable pending further study of competing land uses; blue indicates areas of Federal coal leases.

Focus: Sulfur in Coal—New Insights on the Utilization Potential of High-Sulfur Coals

Although sulfur in coal varies from a few tenths of a percent to more than 12 percent of a coal by weight, coal typically is referred to as either high sulfur or low sulfur. These terms have been variously defined, but high-sulfur coal commonly is assumed to contain more than 3 percent sulfur and low-sulfur coal less than 1.5 percent sulfur. The sulfur generally is partitioned into three forms: sulfate, organic sulfur bonded to carbon, and inorganic sulfide in the iron sulfide mineral pyrite. Various cleaning and washing methods have been developed to remove pyrite before coal is burned, but organic sulfur is an integral part of the carbonaceous matter and can be removed only by treating the combustion gases, an expensive process that produces large amounts of waste. Sulfur as sulfate is only a small part of the total sulfur and generally is not a problem.

On the basis of large-scale averaging, sulfur in high-sulfur coals generally is perceived to be partitioned into about 60 percent in pyrite and 40 percent in organic form, but this relationship should be reevaluated in light of recent research on how sulfur occurs in peat and how its occurrence is modified during the coalification process. Results of this research indicate that organically held sulfur in high-sulfur coal decreases to a low plateau value as formation of pyrite increases, no matter how much total sulfur the coal contains, and examination of chemical data in the USGS NCRDS files provides broad support for this new hypothesis. In planning for industrial use of coal or for government regulation of sulfur emissions from coal combustion, it has been assumed that much of the high-sulfur coal in the U.S. resource base cannot be economically utilized because about 40 percent of its sulfur is in hard-to-remove organic form. It now appears that most of the sulfur in many high-sulfur bituminous coals occurs as pyrite and can be removed by standard cleaning techniques.

This new insight stems from recent research that has developed a picture of changing sulfur distribution during the coalification process. Living vegetation normally contains very little sulfur, and the sulfur in most coal was emplaced from surface waters that permeated the original peat deposits from which the coal eventually formed. These waters carried sulfate, from which sulfur was fixed in the peat in two organic forms: sulfide, which is fully reduced and bonded directly to carbon of the organic matter, and oxidized sulfur, which is combined with oxygen, through which it is bonded to the organic carbon. Research on peats in the Everglades swamps shows that this oxidized organic sulfur is transformed to free sulfide as part of the respiration process of sulfate-reducing bacteria in oxygen-deficient peat swamps. The

free sulfide then reacts with iron to form pyrite. A key finding in the Everglades peats is that, as pyrite formation proceeds, oxidized organic sulfur declines by an equivalent amount. If the bacteria remain active and the transformation goes to completion, the organic sulfur that finally remains is the originally reduced, carbon-bonded sulfide. In the aging and metamorphosis of peat through lignite to coal, free sulfate is progressively lost, pyrite continues to develop, and, eventually, pyrite and organic sulfur are the dominant forms.

NCRDS provides data on the forms of sulfur in thousands of peat, lignite, and coal samples. Analysis of these data suggests that the distribution of sulfur forms evolves differently in low- and high-sulfur peats during their transformation to coal (fig. 33). In both low- and high-sulfur peats, pyrite generally is subordinate, most sulfur is organic sulfur, and high total sulfur simply means high organic sulfur. Low-sulfur coal retains the distribution pattern of sulfur forms in peat, but, as total sulfur increases, pyrite becomes progressively more important and organic sulfur declines, so that organic sulfur rarely exceeds 1.5 to 2.0 percent in sulfur-rich coals. The sulfur in excess of this plateau value for organic sulfur occurs as pyrite.

The plateau value of 1.5 to 2.0 percent for organic sulfur in high-sulfur coal is particularly significant and is probably related to the amount of carbon-bonded sulfide in the original peat-swamp environment. Even if the total sulfur content is as high as 10 percent, about 85 percent of the sulfur in the coal will be in pyrite that can be washed from the coal before it is burned. Sulfur data for all Appalachian coal beds having data in NCRDS and having an average total sulfur content of 7 percent or more indicate that 80 percent of the samples contain 25 percent organic sulfur or less and 50 percent of them contain less than 20 percent organic sulfur (fig. 34). In samples having an average total sulfur content of 10 percent, organic sulfur composes 15 percent of the total sulfur. These values are equivalent to about 1.5 to 2.0 percent organic sulfur in the composition of each coal sample and document the concept of plateau value in a large regional sampling similar to that observed for high-sulfur coals nationwide.

Overall, this research strongly suggests that high-sulfur bituminous coal contains 1.5 to 2.0 percent organically bound sulfur. This conclusion has important implications for the use of high-sulfur coal currently perceived to be unusable. High-sulfur bituminous coal resources should be carefully reevaluated, and the distribution of sulfur forms among coal beds and basins in each coal region of the United States should be documented.

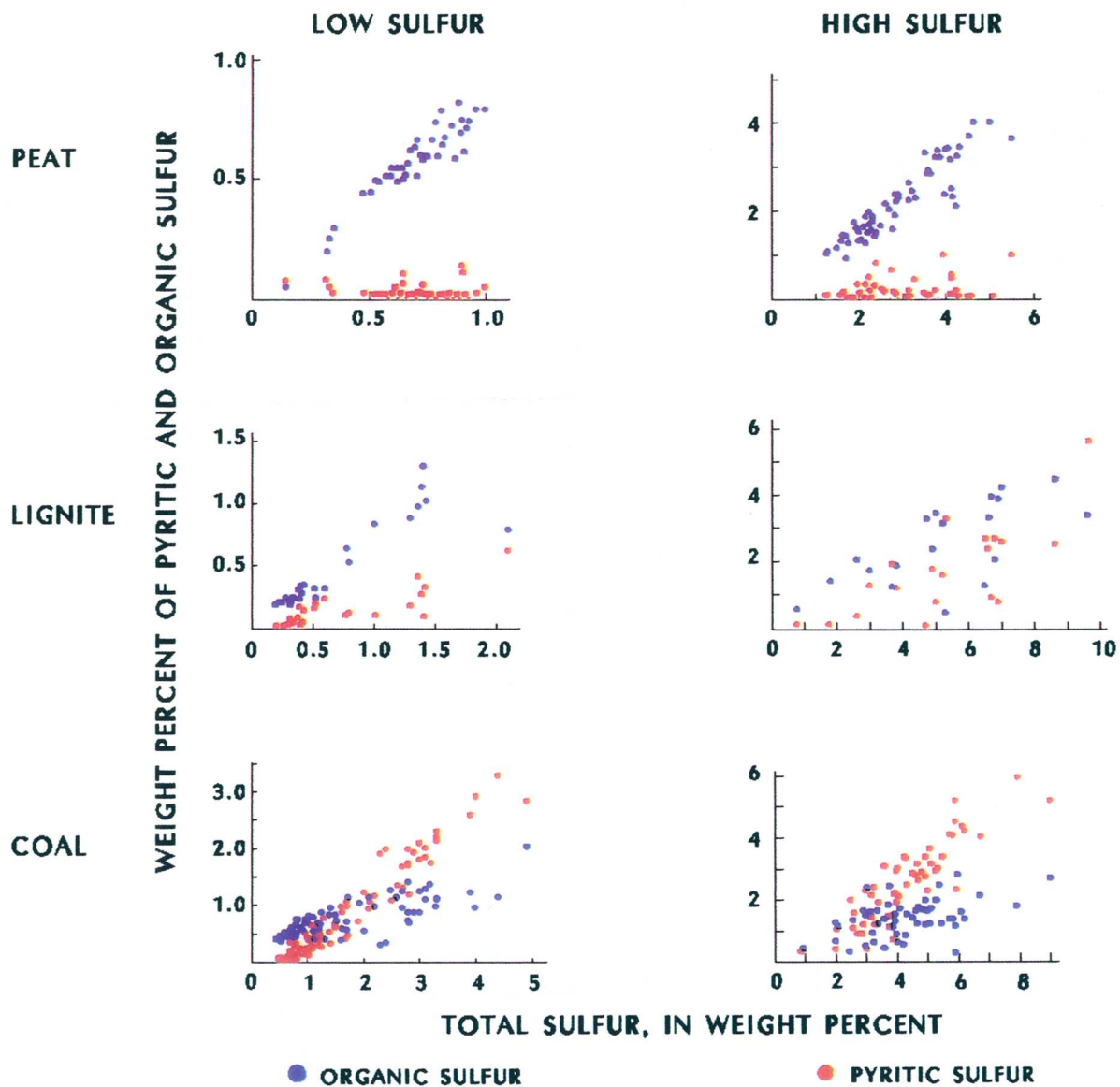


Figure 33. Summary of sulfur data from coal analyses in the National Coal Resources Data System. The data show that low- and high-sulfur coals partition their sulfur differently. In low-sulfur coal, sulfur is dominantly in organic form; in high-sulfur coal, organic sulfur is reduced to a plateau value, and sulfur in excess of that value is in the form of pyrite.

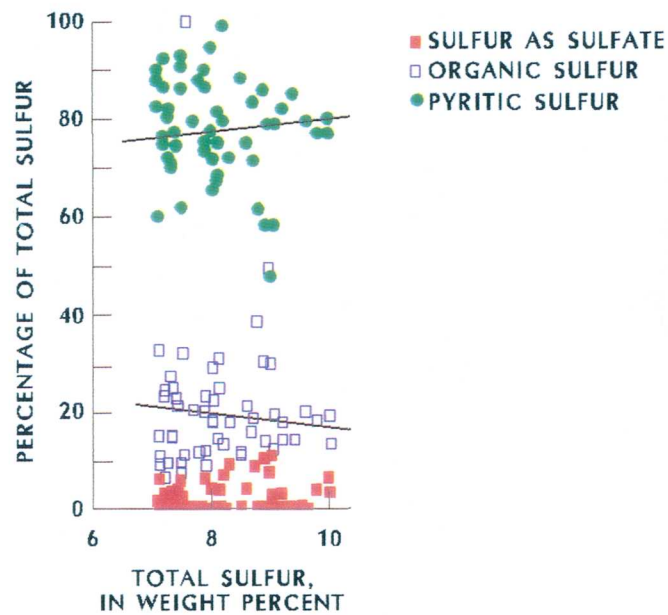


Figure 34. Sulfur content of all Appalachian high-sulfur coal beds containing 7 percent sulfur or more for which analyses are available in the National Coal Resources Data System. The data show that organic sulfur values typically do not exceed 1.5 to 2.0 percent, regardless of the total sulfur content.

HIGHER COST, ALTERNATIVE HYDROCARBON RESOURCES

Although supplies of oil and gas, particularly domestic supplies, will become scarcer and more expensive, it is unlikely that the demand for fuel in both liquid and gaseous forms will decrease substantially in the near future, even given the inevitable advances in design of vehicles and machinery. The United States is extremely rich in possible alternative sources of liquid and gaseous hydrocarbons. These resources are commonly called "unconventional" because producing energy from them requires approaches different from those used for "conventional" oil and gas; they include oil obtained by enhanced recovery techniques, heavy oil, tar sands (bitumen), shale oil, gas from tight reservoir rocks, gas hydrates, and gas from coal.

Although these potential resources are very different one from another, they have two major points in common:

- Hydrocarbons are not yielded as simply as they are in the pumping of conventional oil and gas. Production rates for these resources will be much lower than those for oil and gas, and production will be technologically more complex and expensive. This slower and more expensive production surely will result in decreased availability and higher prices of energy products derived from unconventional resources.
- Problems associated with unconventional hydrocarbons stem mostly from the natural intractabilities of the rocks that contain them and the ways in which they are held in the rocks, and we must have the best knowledge possible about the geologic characteristics of the host rocks. This knowledge will allow us to develop the most economic resources first, to select the most effective existing technologies, and to provide for improvement of extraction technologies, the result being lower production costs and increased rates of availability.

Government's rather unsuccessful efforts to develop a synfuels industry may, to a large extent, be attributed to the premature emphasis on production instead of first establishing a foundation of research and information (Landsberg, 1986). Unconventional hydrocarbon supplies have always been slightly to much more expensive than conventional oil and gas, and their future success depends on their place in a competitive market that is controlled by oil and gas prices. As oil and gas prices rise, unconventional hydrocarbons will become economic earlier if improved production methods have been developed. Development of improved production methods depends greatly on better geologic information about the resources themselves. Better geo-

logic information also will help improve assessments and categorizations of available resources, which, in turn, will permit more informed and economically attractive policy decisions by government and industry planners.

Some higher cost alternative hydrocarbons will become economic sooner than others. Although improved (or enhanced) recovery techniques already are being used in many oil fields and some gas is being recovered from tight reservoir rocks, much research and development must occur before the full potential of these additional resources and reserves can be realized. The economic barriers to full exploitation of resources such as oil shale and tar sands are formidable. Nevertheless, in a context of long-term energy needs and national security, it is important to explore means to utilize the enormous potential of alternative hydrocarbon resources.

ENHANCED OIL RECOVERY

When crude oil is extracted from its reservoir rocks, primary recovery by means of natural reservoir energy and secondary recovery by means of water flooding usually obtain about one-third of the oil actually in place in the rock. Some of the remaining two-thirds probably can be produced by drilling more closely spaced wells to obtain the kind of field growth described in the chapter on oil and gas resources, but a significant percentage of the oil not originally recovered is tightly held either as films surrounding mineral grains of the host rock or in small pores not reached in the original recovery efforts. During the past few years, industry has been actively seeking methods to recover this additional oil. Enhanced oil recovery (EOR) techniques developed thus far include thermal recovery, miscible and immiscible flooding (using, for example, carbon dioxide), and chemical flooding using detergents and surfactants (tables 3, 4). EOR methods are expensive; some require major energy input, which cuts into the net energy gain. In addition, the effectiveness of the methods is quite variable and is highly dependent on the character of the reservoir rocks.

Nonetheless, EOR is a game well worth playing. Nationwide, two-thirds of the original resource left in the ground is a very large amount of oil. Historic production of about 130 BBO, reserves of 50 to 55 BBO, and estimated undiscovered recoverable resources of 80 BBO total 260 to 265 BBO. If this total represents one-third of the original resource, then about 500 BBO have been or will be left in the ground. If this amount of oil could be

Table 3. Enhanced oil recovery projects in the United States
[Data for 1971–1982 from the National Petroleum Council (1984) and for 1984 and 1986 from Leonard (1986)]

Method	1971	1974	1976	1978	1980	1982	1984	1986
Chemical-----	19	18	28	46	42	85	138	206
Miscible-----	22	19	24	30	28	45	66	76
Immiscible CO ₂ -----	0	0	1	4	4	5	18	28
Thermal-----	91	83	106	115	150	139	151	191
Total-----	132	120	159	195	224	274	373	501

Table 4. Production from various enhanced oil recovery methods in the United States
[Production in barrels per day. Data for 1976–1982 from the National Petroleum Council (1984) and for 1984 and 1986 from Leonard (1986)]

Method	1976	1978	1980	1982	1984	1986
Chemical-----	3,400	3,030	2,400	4,410	13,390	16,900
Miscible-----	83,180	76,070	54,820	50,660	82,310	106,870
Immiscible CO ₂ -----	0	0	0	0	700	1,350
Thermal-----	280,000	290,000	352,130	450,200	364,570	479,670
Total ¹ -----	366,580 (4.5)	369,100 (4.2)	409,350 (4.8)	505,270 (5.8)	460,970 (5.2) ²	604,490 (6.8) ²

¹ Values in parentheses are percentages of U.S. daily production.

² DeGolyer and MacNaughton (1986).

considered even remotely to be available as extractable oil, then the United States, whose oil consumption is about 6 BBO per year and whose domestic production is only 3 BBO per year, would be in a fortunate resource position.

However, two factors must be considered: first, the amount of oil that can be obtained by using real-world technology, and, second, the rate at which enhanced recovery can be expected to produce oil. In 1984, the National Petroleum Council issued a major study on EOR prospects and problems. A base case using current EOR technology was examined and projected over the next 30 years. The projections show that, at an oil price of \$30 per barrel, EOR will add only about 14.5 BBO to U.S. oil supplies (fig. 35) and that annual production in about the year 2000 will be 0.4 BBO (fig. 36). If projections assuming advances in recovery technology are made, then ultimate recovery increases to 27.5 BBO, and annual production in the year 2000 is about 0.6 BBO. At \$20 per barrel, the base case increases ultimate U.S. production by only about 8 BBO, and advanced technology development will not be supported. The sharp decrease in oil prices during 1986 appears to have produced the result projected by the National Petroleum Council in that

numerous trade journal articles indicate significant industry cutbacks in EOR research.

It is difficult to determine how soon the economics of petroleum will bring EOR to the fore and what technologic advances may occur to make EOR more effective. It is not difficult, however, to predict that improving EOR will require sophisticated geologic knowledge. Reservoir rocks have unique geologic characteristics, and both selection of the proper recovery method and improvements in that method depend on a knowledge of the porosity, permeability, mineralogy, and chemistry of reservoir rocks and their contained natural fluids. Such knowledge can be derived only through detailed studies of drill-core samples and well measurements. Information from these studies can be used to construct models of the original depositional environment of the sediments and the many changes that the sediments undergo after deposition as the result of interaction with ground water.

An enormous amount of oil potentially is available for EOR. Can we really expect to obtain only 5 percent of this oil and then only at greatly increased prices? The remaining 95 percent provides a major target and incentive for geologic and engineering research.

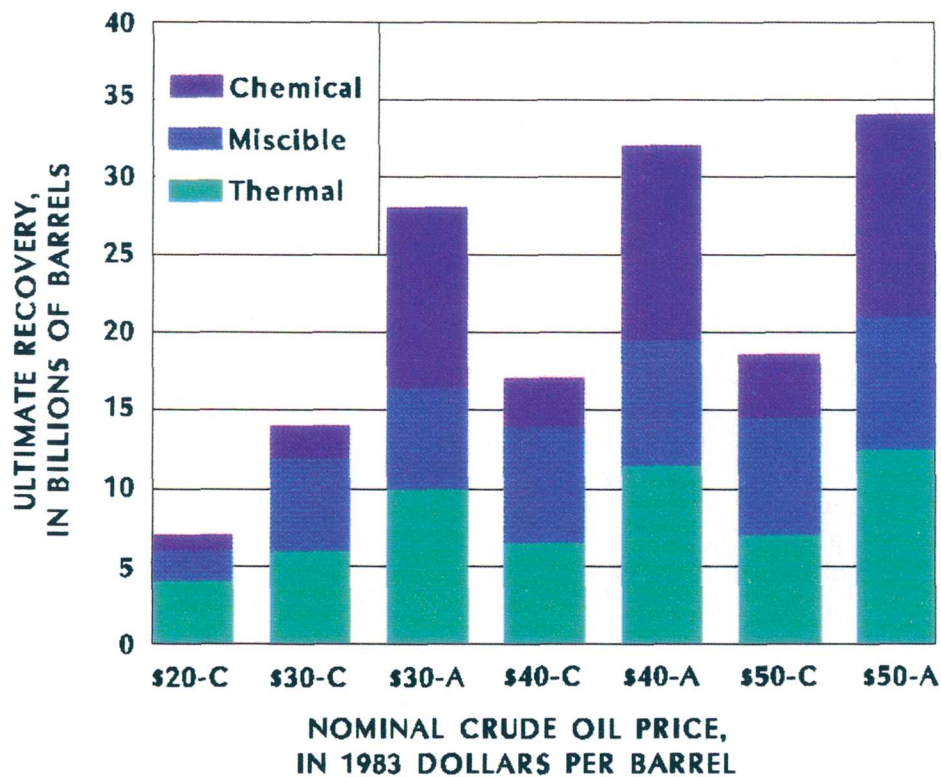


Figure 35. Ultimate recovery of oil in the United States calculated by using both current (C) and advanced (A) enhanced oil recovery technology. Dollar amount shown is price per barrel. Modified from National Petroleum Council (1984, p. 71).

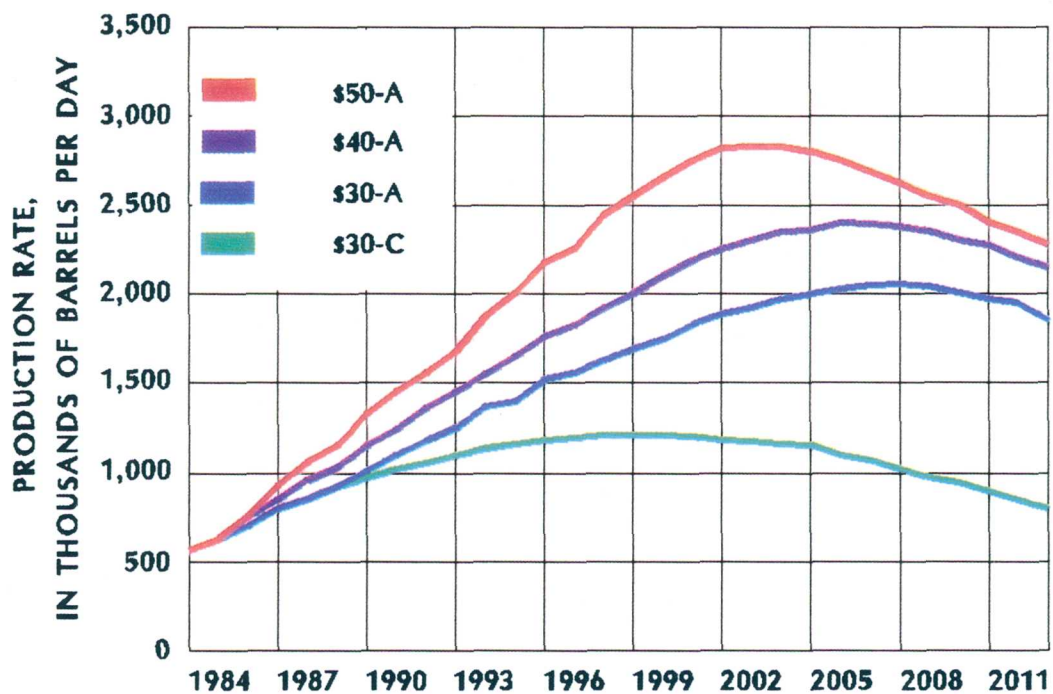


Figure 36. Projected daily production from enhanced oil recovery (relative to crude oil price) calculated by using both current (C) and advanced (A) enhanced oil recovery technology. Dollar amount shown is price per barrel. Modified from National Petroleum Council (1984, p. 68, 76).

Focus: Geologic Studies Related to Enhanced Oil Recovery

Recent studies of reservoir rocks indicate that it is critical to understand the fine details of these rocks. An important reservoir rock, the Minnelusa Formation in the Powder River basin of Wyoming, was deposited by a combination of marine and wind depositional processes. These varied depositional processes produced heterogeneous sandstone bodies. Highly permeable zones are adjacent to impermeable (or tight) zones, and fluids used in EOR can be easily channeled away from much of the oil-bearing rock. Porosity and permeability in the Minnelusa Formation are highly variable; the original porosity and mineralogic character were controlled by the depositional process, which in turn controlled how and where secondary porosity developed as the result of the later passage of ground water (fig. 37).

In rocks of the Minnelusa Formation, original cementing material around the sand grains was partially dissolved to create complex secondary pore-space pathways; these pathways were then partially filled by very fine grained minerals. If recovery fluids are used under pressure, this late-growth fine-grained mineral matter can be dislodged and block other pores in an uncontrolled fashion and thus interfere with oil recovery. Moreover, some of the late-growth minerals are clays and zeolites that can swell or react chemically upon contact with certain recov-

ery fluids and block pores or cause other problems. Thus, for each target reservoir rock, a well-designed recovery operation should begin with a knowledge of the depositional environment and an understanding of the mineralogy, chemistry, and primary and secondary porosity of the rocks, as well as the sequence in which these developed.

In recognition of the importance of EOR and in order to fill part of the gap resulting from the oil industry's shutdown of research, the USGS is extending its research program to include study of an increased number of representative reservoir rocks and to build a data base of pertinent reservoir characteristics. One of the program's goals is to compile geologic and engineering information from a national file of well data and to study in detail well cores held by the USGS in its National Core Library. The program also includes the use of complex new geophysical techniques to measure rock properties in drill holes and in core samples. Overall, the program is designed to encompass studies of:

- Detailed reservoir rock characteristics, including granularity, mineralogy, and chemistry, special attention being given to clays and other reactive minerals and to fluid-flow pathways. Clay minerals are extremely important because they critically influence reservoir quality, and, if the types and

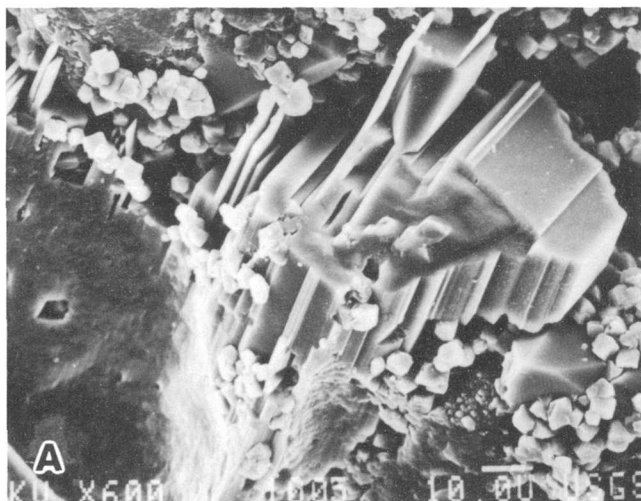


Figure 37. Scanning electron photomicrographs of eolian sandstones from the Minnelusa Formation, Powder River basin, Wyoming. *A*, Secondary porosity has resulted from anhydrite dissolution, and small dolomite rhombs have formed both along the pores and on the remnant anhydrite. The dolomite rhombs and the complex topography of the remnant anhydrite increase tortuosity and surface area in the pore throats. During reservoir enhancement, the dolomite can detach from the walls of the pore throats, be carried in the fluid, and later plug up or restrict pore throats. *B*, The clay minerals smectite and illite/smectite (spongy areas and small crystals) are common pore-lining cements and can react with fluids and cause swelling and increased surface area within the pores. Large crystals are anhydrite. (Photographs courtesy of C.J. Schenk.)

distribution of clay minerals are not adequately understood before application of EOR techniques, reservoir porosity and permeability can be irreversibly damaged. Given this information, conceptual models can be achieved to understand and predict variations in pore-space pathways and fluid movement as a function of the basic geology of the reservoir rock.

- Organic geochemistry, including character, level of alteration, trace-metal content, sources of the oil, and the possible degradation of oil by postdepositional processes.
- Reservoir classification, a categorization based on geologic, engineering, and production attributes, to help guide selection of recovery techniques and possible improvements of these techniques.
- Resource assessment, an estimation of potentially recoverable resources by category of reservoir, based on studies of selected reservoirs and extrapolation to a larger population of reservoirs.

HEAVY OILS

Some petroleum reservoirs contain viscous hydrocarbons known as heavy oils or extra-heavy oils. These oils are too viscous to flow in response to the pumping or flooding techniques used to produce conventional oil. They typically are viscous either because they have been altered more than normal oils through geologic time or, more commonly, because they are contained in reservoirs so shallow that rock temperatures are too low to keep the oils mobile. Many potential heavy-oil resources are in reservoirs at depths of only 1,000 to 5,000 feet, and, if recovery techniques are developed, these shallow depths could make the oils economically attractive.

Although heavy oils occur widely in small accumulations, most heavy-oil resources occur in a more restricted fashion (fig. 38). Future exploitation probably will involve only 20 to 60 fields, most of which are in California, the gulf coast, and Alaska (table 5). The original heavy-oil resources of California are estimated at about 35 BBO, of which 10.2 billion BBO have been

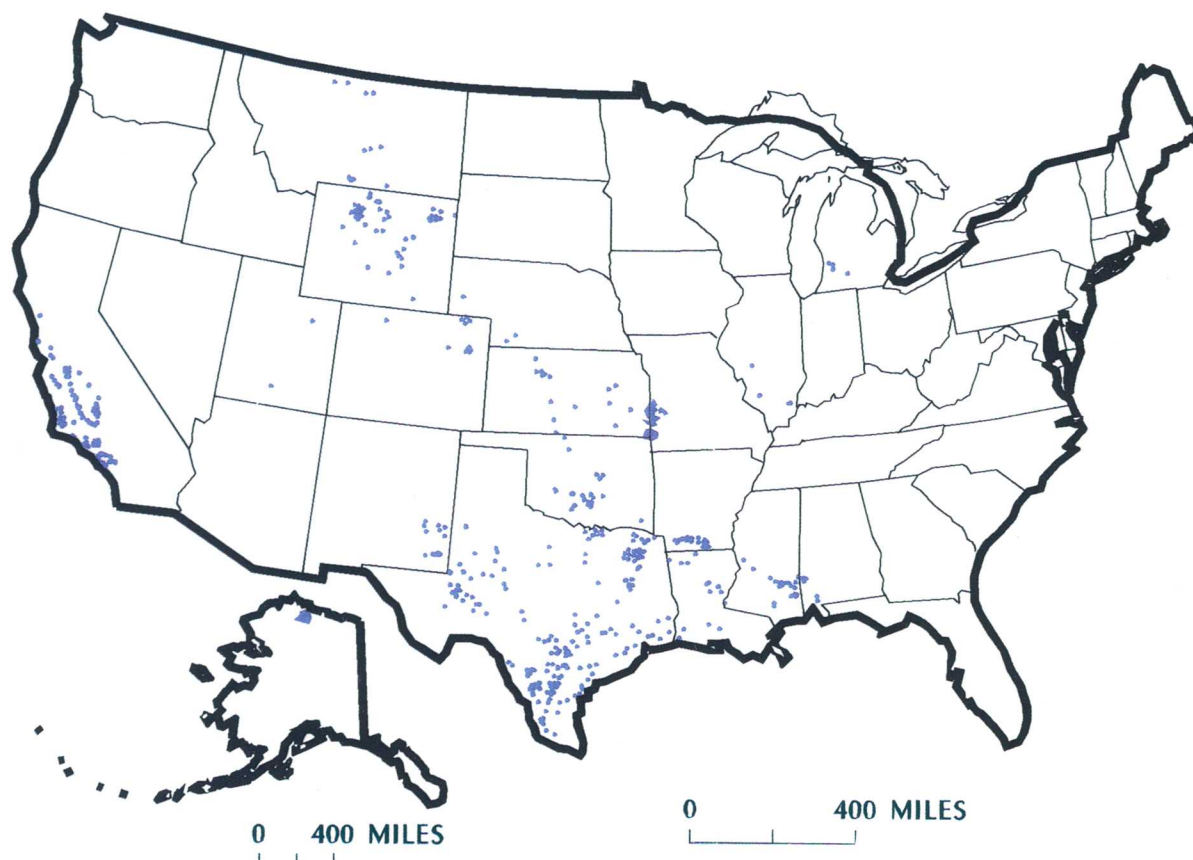


Figure 38. Heavy-oil resources in the United States.

produced through 1984. The heavy-oil resources of Alaska may be as much as 40 BBO in shallow rocks overlying the giant Prudhoe Bay field of conventional oil. All these numbers represent original oil in place and not recoverable oil; presumably, only a small fraction of the total heavy-oil resource of the United States will ever be produced. It should be noted that the heavy-oil resources of the United States are dwarfed by the enormous potential resources of Venezuela and the U.S.S.R.

Heavy oil is extracted by using EOR techniques (in particular, steam injection). In the future, shallow heavy-oil reservoirs conceivably may be developed by using underground techniques such as mining or horizontal drilling, but use of these techniques will result in significantly higher prices. The effective use of all heavy-oil recovery techniques will benefit from improved geologic knowledge. The heavy-oil resources of the United States have been only crudely estimated, and many more studies similar to those described for EOR are needed to determine the distribution and field size of potentially recoverable heavy oils and the geologic characteristics of their reservoirs.

Table 5. Production from heavy-oil deposits in the United States

[Cumulative crude oil production through January 1 of the year listed for most, though not necessarily all, reservoirs in State]

State	Year	Cumulative crude oil produced, in millions of barrels
Arkansas-----	1982	605
California-----	1985	10,202
Louisiana-----	1982	1,002
Mississippi-----	1985	261
Texas-----	1985	1,173
Wyoming-----	1985	1,177
Other States-----	Not applicable	147

TAR SANDS

The term "tar sands" is used to refer to both sedimentary rocks and unconsolidated sands that contain an asphaltic substance called bitumen, which is not mobile at reservoir conditions and cannot be extracted by conventional petroleum recovery methods. Bitumen-bearing geologic materials include sandstone, limestone, dolomite, conglomerate, siltstone, and unconsolidated sand. Most tar sands in the United States are in fields that each contain more than 100 million barrels of oil in place (fig. 39). The total tar sand resource of the United States is about 53 BBO in place, 22 BBO of which are measured reserves and the rest speculative reserves (fig. 40). Another 1 BBO is estimated for smaller fields. More than two-thirds of the estimated resource is in Utah, Alabama,

California, and Texas, and a very large but only crudely estimated speculative resource is in Alaska.

Bitumen recovery is virtually 100 percent if the tar sand deposit is amenable to open-pit mining, as are the giant Athabasca deposits in central Canada. Most deposits in the United States, however, have geologic or physiographic settings that probably will require either underground mining or in-place recovery techniques similar to those used for EOR.

Although most natural bitumen deposits look alike superficially, each deposit is unique in the geochemistry of its hydrocarbons and in the mineralogy and grain texture of its reservoir rock. The highly altered bitumens characteristic of most tar sand deposits represent only about 20 percent of the oil that existed before degradation by bacterial activity, dissolution of some components by freshwater, and evaporation of components having low boiling points. Oil from these tar sands is a residue, not unlike the residual oil in refinery stills, and it contains all of the most stable components of the original oils, including complex heavy molecules of asphaltenes and resins and other hydrocarbons rich in nickel, vanadium, and nitrogen-oxygen-sulfur compounds. Characteristics such as viscosity, specific gravity, and vanadium, sulfur, and asphaltene content should be determined before attempts at recovering the bitumen are made. Only then can the technological and economic aspects of producing, upgrading, transporting, and refining these hydrocarbons be assessed.

The geologic setting and the detailed mineralogic and chemical compositions of both reservoir rocks and surrounding rocks are important. For example, although tar sand deposits around the margin of the Uinta basin in Utah are among the largest in the United States and are reasonably attractive recovery targets, thermal recovery methods (steaming) have been unsuccessful because of porous "thief" zones in the rock sequence into which injected steam is lost to recovery. The sandstones in the reservoir rock sequence are quite heterogenous as a result of both the processes and the environments of their deposition. Individual lenticular tar-bearing sandstones are enclosed in finer grained rocks and are not well interconnected. In-place recovery must target individual sandstones, and, as a result, the amount of reservoir rock from which oil can be obtained in a single attempt is greatly reduced. The sandstones have a complex primary and secondary mineralogy and contain many clays and other minerals that may interfere with recovery (fig. 41). The original pores of the sandstones contain late-growth mineral grains that are unstable in the presence of some recovery fluids, and formation damage can easily occur if recovery methods are not specifically designed for the particular sandstone. Moreover, the tar appears to occupy secondary pores that developed erratically. All of these

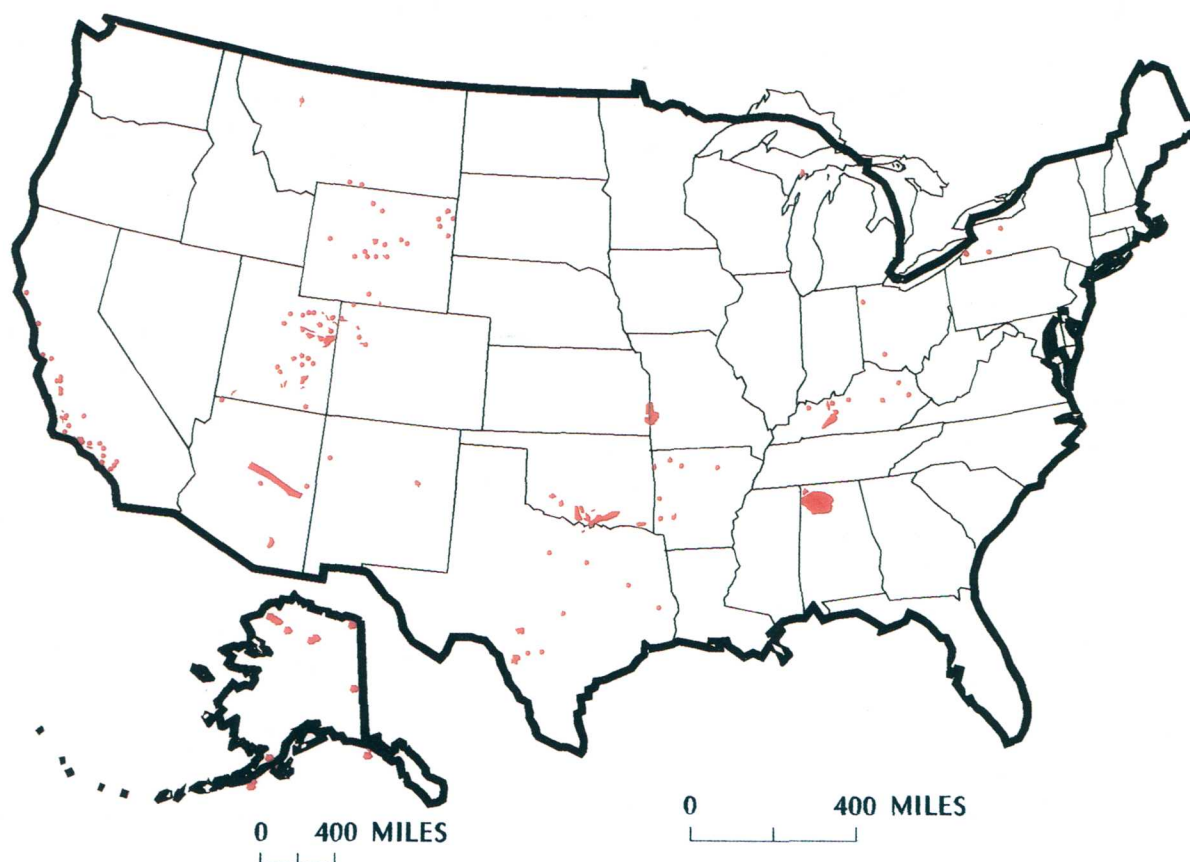


Figure 39. Tar sand resources in the United States.

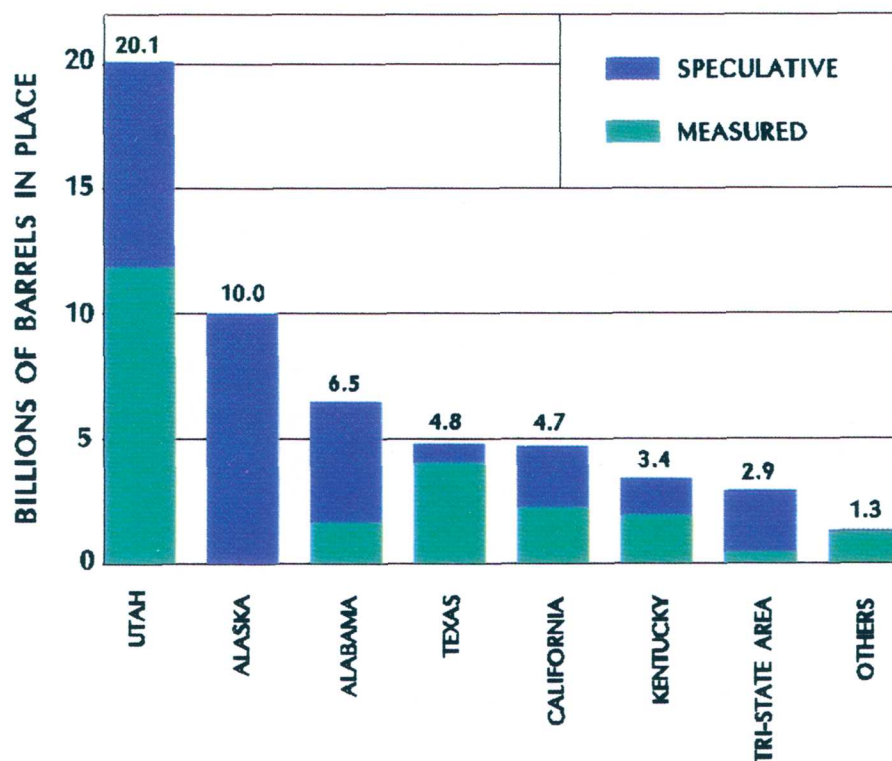


Figure 40. Distribution of tar sand resources in the United States. Tri-State area includes parts of Missouri, Kansas, and Oklahoma. Modified from a figure prepared for the U.S. Geological Survey by Lewin and Associates (1983).

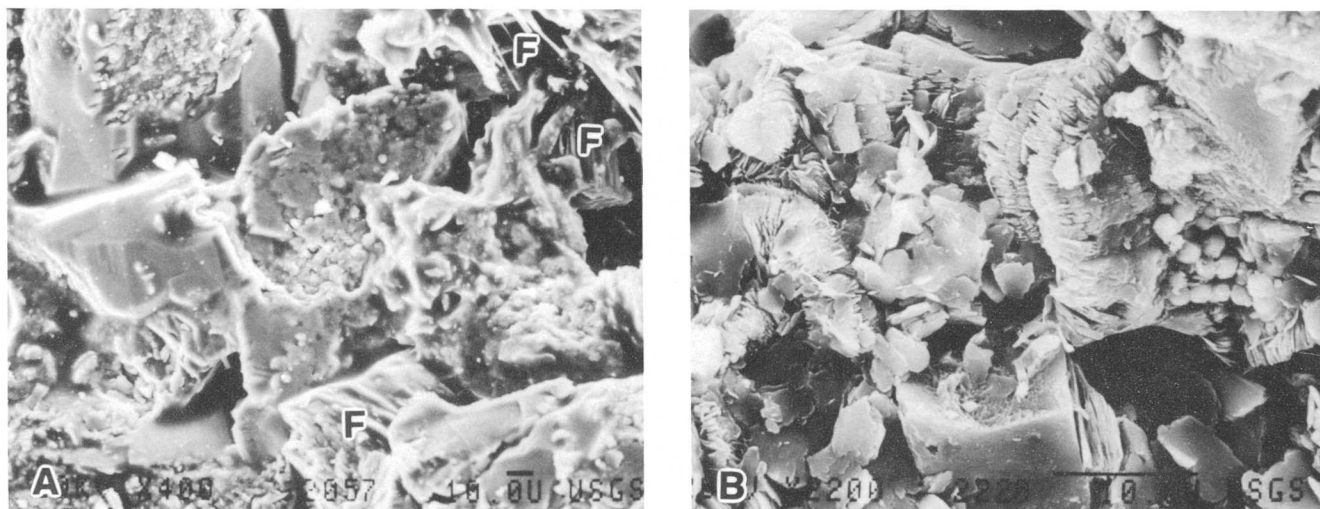


Figure 41. Scanning electron photomicrographs of the Sunnyside tar sand, Uinta basin, Utah. *A*, This bitumen-bearing tar sand is mineralogically complex, and, as a result, bitumen recovery will be difficult. The bitumen (pasty material) occupies the minute topography of the framework grains (areas labeled F and large blebs) and late-growth minerals (small crystals) and is difficult to separate from these minerals. *B*, In a nonbitumen-bearing sandstone, kaolinite (plates and elongate masses of plates), pyrite (small cubic crystals), and dolomite (large cubic crystals) combine to produce extremely large surface areas that reduce permeability and make access of recovery fluids difficult, if not impossible. (Photographs courtesy of C.J. Schenk.)

problems are difficult to overcome by using only an engineering approach, but bitumen recovery may be significantly improved if detailed geologic information on the origins and characteristics of the reservoir sandstones is available.

OIL SHALE

Oil shales are fine-grained sedimentary rocks that contain kerogen, which produces oil and combustible gases upon destructive distillation. Kerogen consists of carbon, hydrogen, oxygen, nitrogen, and sulfur in varied proportions, depending on the organic matter from which it was derived and on the postdepositional chemical changes and thermal history of the oil shale. Oil shales generally form in lake or marine environments, and the kerogen is derived mostly from algae and aquatic organisms. A good grade of oil shale typically contains 15 to 20 weight percent kerogen; the remainder of the rock is composed of mineral matter usually having a complex mineralogic and chemical composition. Some oil shales contain other organic matter such as bitumen and humus (derived from land plants), depending on conditions of deposition, proximity to land masses, and thermal history.

Oil shales are a low-grade energy resource in comparison with other fossil fuels. In terms of Btu per ton, the amount of heat energy in oil shale is about one-eighth of that in crude oil (fig. 42). Estimated resources of shale oil, however, are about 14 times as great as those of conventionally recoverable oil, and

estimates of about 2 trillion barrels of shale oil probably will increase as more information is gathered on less well known shale deposits.

The relatively low heat energy in oil shales results from dilution of kerogen by the large proportion of mineral matter in the shales. This mineral matter contributes to mining, processing and waste disposal problems, and costs. Unlike crude oil, which is sent directly to the refinery, or coal, which commonly requires only crushing, screening, and perhaps washing before it is burned, oil shales require significant handling, retorting, and upgrading before they are refined, and attention must be given to environmental concerns in disposing of waste materials. Nevertheless, the large amount of oil that potentially can be extracted from oil shales in the United States probably ensures its eventual inclusion in the national energy mix. The future of oil shales as an energy resource will be enhanced by continued research on the geologic, mineralogic, and chemical character of the principal oil shale deposits in the United States as a basis for improving both resource assessments and extraction techniques. At the present time, oil is plentiful and cheap on world markets, and oil shale development efforts and the research that underlies these efforts have been almost completely abandoned by industry. The USGS is continuing a small program of research on oil shales that is designed to build on past information and to bridge today's lull in activity in order to ensure better information for tomorrow's needs.

Oil shales are widely distributed in the United States and vary greatly in type and geologic age (fig. 43).

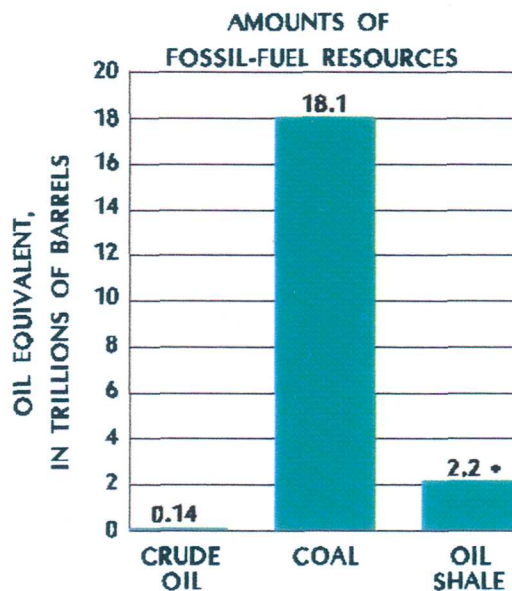
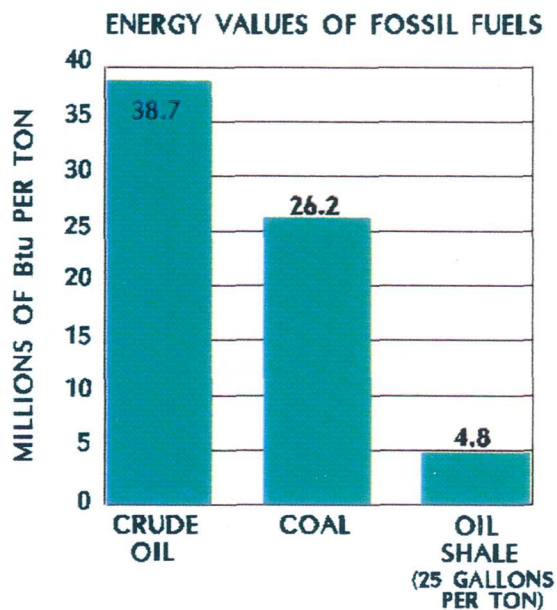


Figure 42. Energy values and resource amounts of oil, coal, and oil shale in the United States. Data from Duncan and Swanson (1965), Averitt (1975), Dolton and others (1981), and the American Petroleum Institute (1982, sec. 15, table 3).

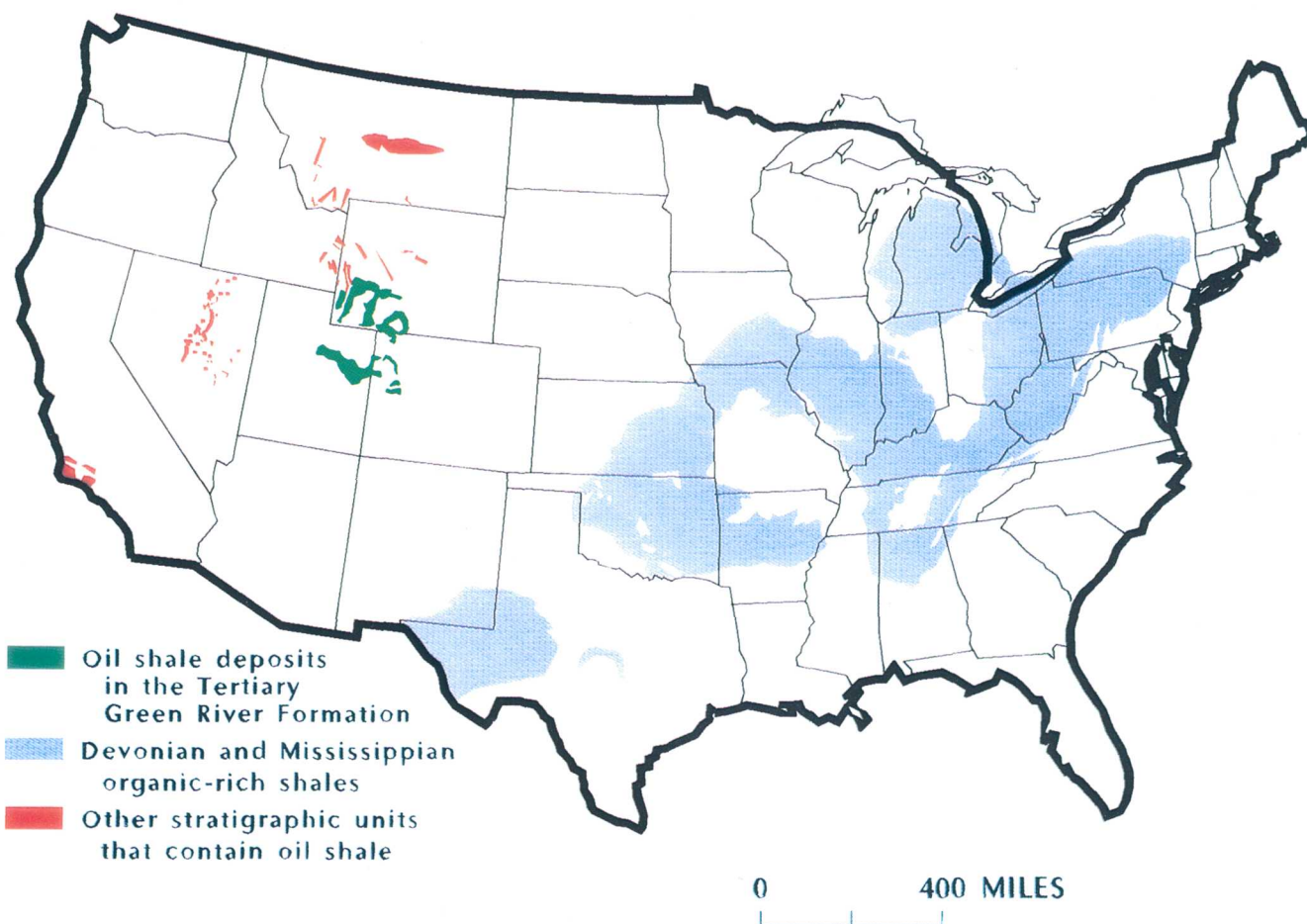


Figure 43. Oil shale resources in the United States. Modified from L.J. Schmitt and J. Roen (written communication, 1986).



Figure 44. Block of white-weathering high-grade oil shale from the Green River Formation showing evenly bedded laminae characteristic of deposition in undisturbed oxygen-deficient lake waters. Beneath the weathered surface, the oil shale is brownish black. (Photograph by J.R. Dyni.)

Only the largest deposits have received much study and analysis, and, even for these deposits, much more detailed work is necessary to support economic extraction attempts. The two largest deposits in the United States are the Green River oil shales in Colorado, Utah, and Wyoming (lake origin, Tertiary age) and the black shales of the Appalachian plateau (marine origin, Devonian-Mississippian age). Thousands of assays and other analytical data from hundreds of drill holes are available for the Green River shales, especially those in Colorado. Analytical data for the eastern oil shales are sparse relative to their wide distribution, and resource estimates for these shales are much more uncertain than those for the Green River shales.

The Green River oil shales contain an estimated 1.8 trillion barrels of oil in beds that will yield 15 or more gallons per ton (Donnell, 1980). In Colorado alone, these deposits contain an estimated 1.2 trillion barrels. Most of these shales can be reached by open-pit, underground room-and-pillar, and in-place retorting methods of mining or extraction. The distribution of richness in the shales is a function of the environments in the ancient lake in which the shales were deposited (fig. 44), and geologic mapping and compilation of assay data by the USGS have resulted in delineation of zones of estimated oil yields (fig. 45). If this information is overlaid on a map showing basin topography, significant amounts of shale can be seen to

have overburden thin enough to permit strip mining, and, as prices of competing fuels rise, these shales will become economically more attractive. Strip mining economics also may be improved if the enormous quantities of the industrial minerals nahcolite (a source of soda ash) and dawsonite (a source of alumina) in the rock sequence can be mined as coproducts with the oil.

Government and industry have invested billions of dollars in an effort to make the oil shales of Colorado an economic resource, but costs have always been higher than the price of oil. This differential cannot be overcome by good geologic information alone, but, if oil shale is ever to reach an economic threshold, geologic information is an essential ingredient in improving the processes of site selection, mining, retorting, and waste handling.

Site selection to achieve a combination of richest yields and thinnest overburden or to locate shale zones amenable to underground mining or in-place extraction is paramount. In addition, the extraction process being considered must fit the mineralogy and chemistry of the shale. Open-pit and underground operations must not disrupt aquifers or adversely affect other aspects of the local ground water; for example, they must not introduce pollutants or adversely affect the natural water chemistry. One study by the USGS resulted in important new information on natural rock fracture systems in the shale that can be used to help determine mining, crushing, and

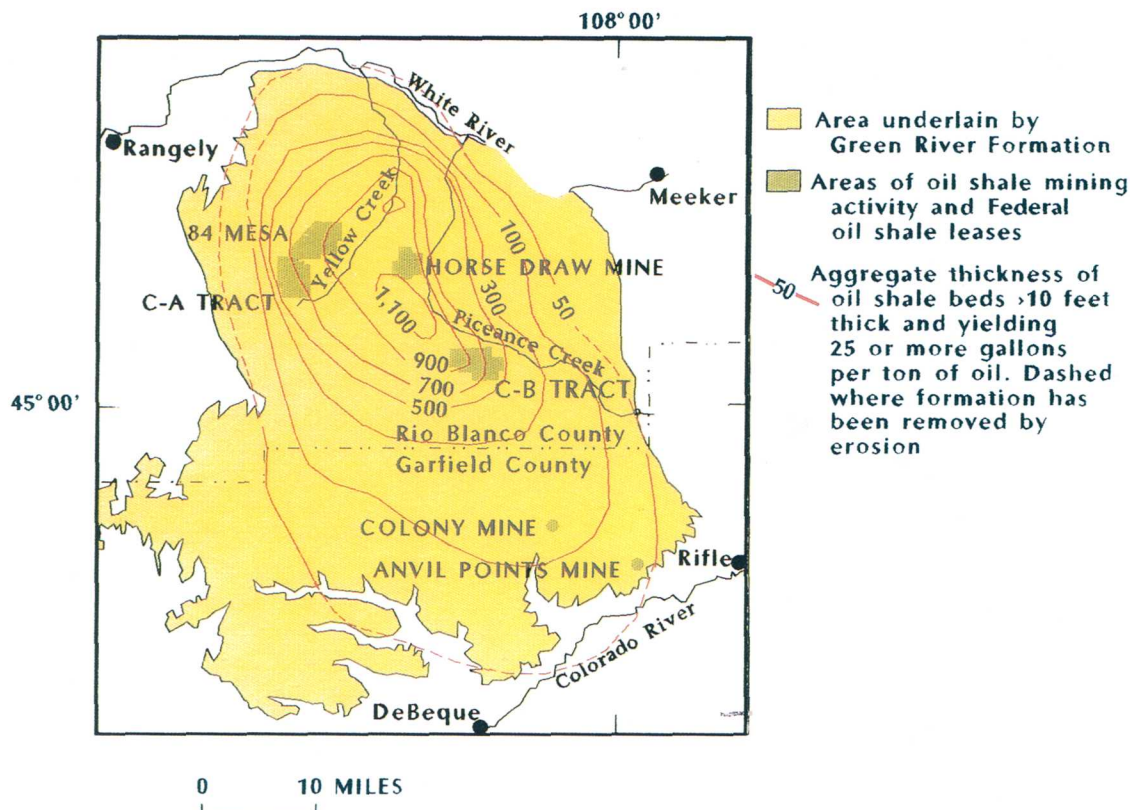


Figure 45. Areal extent of the Green River Formation in western Colorado, locations of several oil shale operations, and contours of the aggregate thickness of oil shale beds yielding at least 25 gallons of oil per ton. Modified from C.W. Keighin (1975, p. 67).

retorting procedures and to handle problems associated with ground-water movement in mine areas.

Numerous retorting devices and methods have been designed, some of which have been tested at pilot scale. Different oil shales may behave quite differently in the retort, which distills oil and gases from the raw feedstock. Breakage and fracture characteristics of the shale are important. The reactions of different mineral components (in particular, carbonate and sulfide minerals) at various retorting temperatures can cause heat loss or problems of water chemistry leading to environmental concerns.

No single retorting process has yet emerged as the best method for retorting oil shale. Newer, innovative technologies, including microwave processing, hydro-retorting, and solvent extraction, may lead to methods of economically recovering shale oil. But any and all of these methods, like those previously tried, depend on characteristics of the target shale, such as mineralogy, kerogen and trace-element contents, depth, thickness, and grade. Beneficiation (upgrading) of oil shale before retorting by liquid flotation and mechanical separation techniques has been tested at laboratory scale but must be tailored to the precise physical, mineralogical, and chemical characteristics of the shale to be treated.

Some shale oil tested in jet engines is corrosive, and piping has been corroded during some extraction tests. The cause of this corrosion is not known, but one suspicion focuses on the presence of fluorine, which is in the fluorine-bearing mineral phase apatite in some shales. Oil shale varies both laterally and vertically, and the identity and distribution of fluorine-bearing minerals in oil shale are not well known. Other deleterious trace elements in oil shale (also of unknown detailed distribution) include mercury and arsenic, both of which poison catalysts in the refining process.

Environmental concerns in the mining and processing of oil shale include (1) release of gaseous and particulate stack gas effluents from above-ground retorts; (2) dust resulting from large-scale open-pit mining; (3) contamination of surface and ground water by the dissolution of soluble organic and inorganic constituents from piles of raw and retorted shale and overburden; and (4) compaction and slope stability of waste piles and their long-term exposure to erosion and dissolution of soluble materials.

Some organic constituents of oil shale are carcinogens. These compounds are in the shale oil as well as in the organic waste products (Savitz and others, 1984). Little is known about either their concentrations in the

shale or shale oil or their levels of toxicity to man, livestock, wildlife, and native vegetation. Potentially toxic elements include fluorine, sulfur, arsenic, boron, molybdenum, mercury, and lithium. Little is known about the concentration, distribution, and mineral residence of these elements in the oil itself. The USGS and others have initiated geochemical studies of some of these potentially harmful elements in order to understand and predict their distribution and abundance in oil shale and their concentrations and leachability in retorted shale. In addition, the USGS has determined concentrations of various trace elements in selected native plants in the Piceance basin of western Colorado in order to establish a baseline of geochemical data under natural conditions before mining. When an oil shale industry is established, these data will be useful in monitoring trace elements of environmental concern.

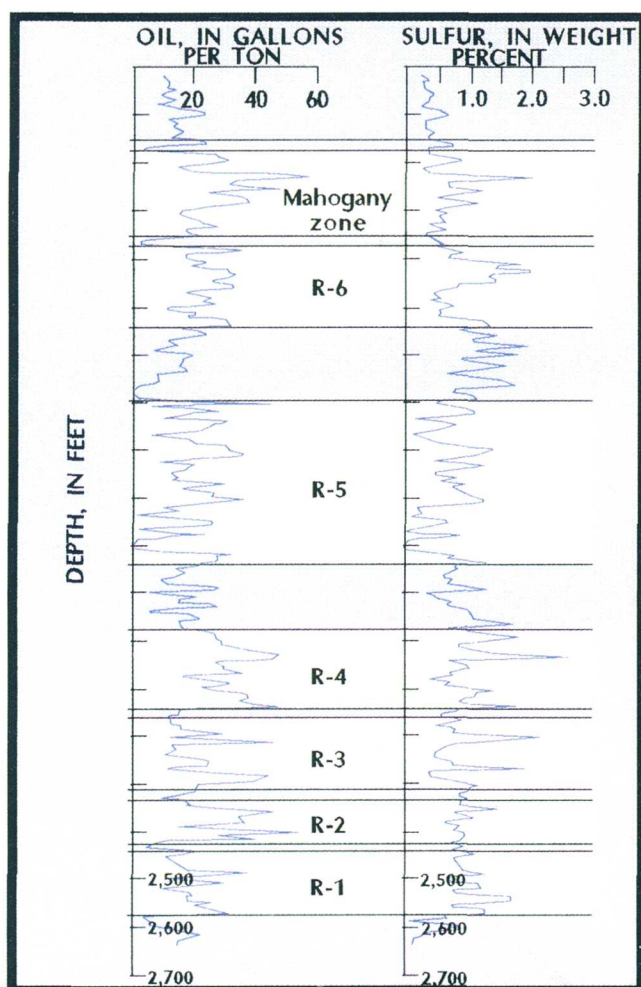


Figure 46. Chemical analyses of Green River shale oil from a drill hole in the deeper part of the Piceance basin of Colorado. Geochemical data help the process engineer determine the amount of sulfur that can be recovered as a byproduct from oil shale. Zones R-1 through R-6 and the Mahogany zone are oil-rich layers in the shale sequence.

Much remains to be learned about our major oil shale resource, the Green River Formation in Colorado, Utah, and Wyoming. Current research by the USGS includes geologic mapping, stratigraphic and basin analysis studies, resource inventories of the Colorado shales, geochemical studies of selected elements, compilation of a large computerized data base, and the accumulation of government and industry drill-core samples to be made publicly available for further research. A series of subsurface stratigraphic sections of the Piceance basin in Colorado is being produced to detail rock types and resources of oil shale, nahcolite, and dawsonite. The sections pass through each of the major oil shale project areas in the basin, including Federal lease tract C-a and a proposed offsite waste disposal area for the tract, Federal lease tract C-b, the Colony project, and the government experimental mines at Horse Draw and Anvil Point (fig. 45). These sections delineate a leached zone in the upper part of the oil shale sequence that is an aquifer that may cause problems in mining. They also show correlations between depositional character and mineralogical and trace-element patterns, information that will be useful before shale mining and processing. For example, we know that the lateral and vertical distribution of sulfur is partly controlled by depositional conditions and that the concentration of sulfur is partly related to the abundance of kerogen (fig. 46).

Oil shales above the well-known oil-rich Mahogany zone (fig. 47) in the upper part of the Green River Formation also are targeted for study. These lower grade oil shales (5-25 gallons per ton) could be exploitable



Figure 47. Aerial view of the Mahogany oil shale ledge (ML) and underlying oil shale zones on the northern slope of the East Fork of Parachute Creek, near the Union oil shale mine, southern Piceance basin, Colorado. (Photograph courtesy of J.R. Dyni.)

resources if deep open-pit mining in parts of the basin is ever economically feasible.

In the past few years, Devonian oil shales in the Eastern United States have received considerable attention as a potential source of energy. These large, potentially strippable deposits occur in several States (fig. 43). Currently available resource estimates need to be revised but are on the order of 400 BBO for those shales containing 10 gallons per ton or more. Although conventional Fischer assay yields for Devonian oil shales are only one-half of those for Green River shales, it recently has been discovered that such assays do not measure a rock's total hydrocarbon potential. In fact, an experimental hydroretorting technique releases as much as 200 percent more oil than Fisher assays indicate is in Devonian shales. Because these Devonian shales contain less carbonate, they should be easier to crush and beneficiate than Green River oil shales and should pose less of a problem of leaching in terms of large amounts of soluble compounds. Water for processing, a problem in the Western States, is abundant, and labor, transportation, power, and markets are nearby. These factors, together with the potential for improved retorting, may help offset the fact that eastern oil shales are thinner and less oil rich than Green River shales.

Kerogen-rich shales occur in several other parts of the United States, but their oil resource potential is not well known. Some of these shales are irregularly distributed and are in geologic and physiographic settings not amenable to exploitation. Occurrences in Montana and Nevada, however, may contain billions of barrels of shale oil. This potential calls for basic geologic investigation, although perhaps at a lower priority than investigations of the more important deposits described above.

GAS HYDRATES

Gas hydrates are compounds of solid water (ice) and gas, usually methane. Pressure and temperature conditions suitable for formation of gas hydrates are found in arctic permafrost regions (fig. 48) and beneath the sea floor of outer continental margins and ocean basins. In arctic regions, gas hydrates occur not only in permafrost but also below the base of permafrost at temperatures above the freezing point of water.

Significant quantities of gas hydrates have been detected in several permafrost regions of the world, including the North Slope of Alaska, both onshore and offshore. Marine seismic reflections offshore from the North Slope in the Arctic Ocean and in the Blake

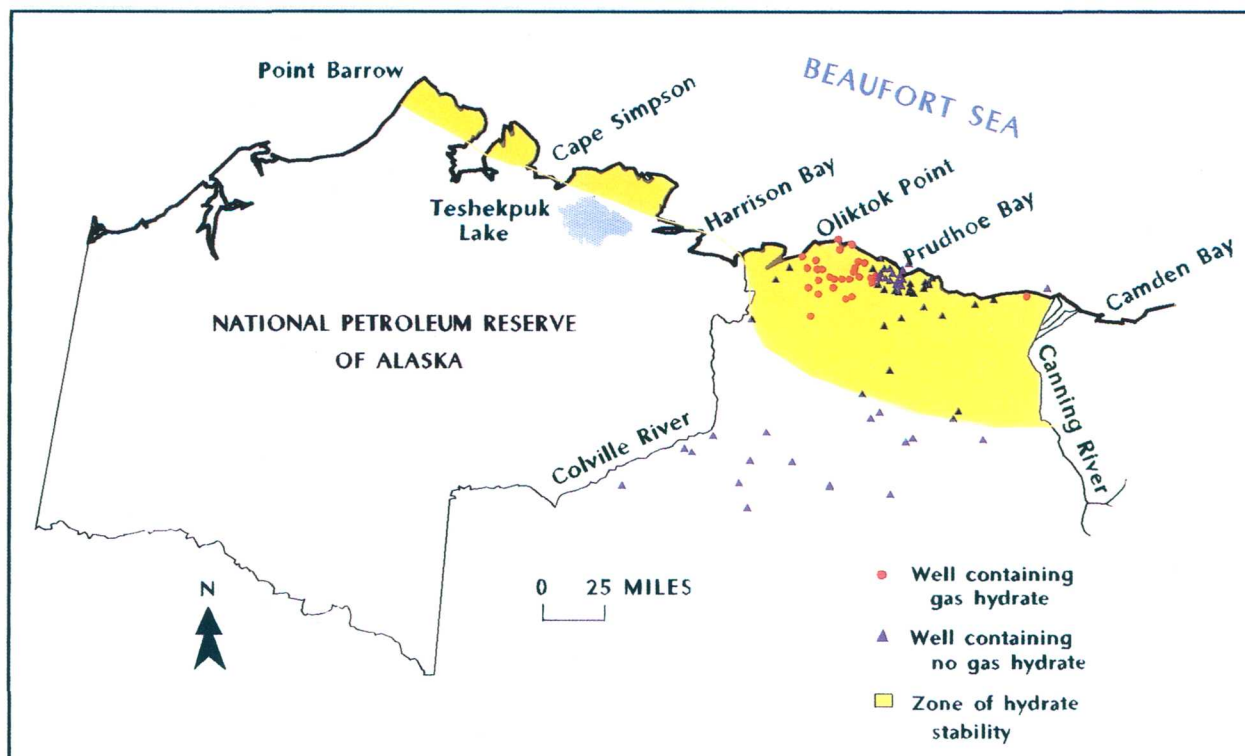


Figure 48. Areas in which gas hydrates are stable, North Slope, Alaska.

Plateau-Bahamas region of the Atlantic Ocean show features known as bottom-simulating reflectors, which are construed to indicate gas hydrate occurrences. Seismic data defining the extent of gas hydrates offshore from the North Slope and in the Blake Plateau area are reasonably complete, and limited seismic data indicate the possible existence of gas hydrates in the Bering Sea, in a zone along the southern side of the Aleutian arc, and on the Pacific slope off northern California.

The potential gas resource contained in gas hydrates in U.S. Territories was reviewed by the Potential Gas Commission (1981). Information on occurrence, thickness, continuity, and gas content is highly speculative, and reliable estimates are not possible. Estimates of worldwide gas hydrate resources range from 500 to 1,200,000 TCFG, and, although any estimate of world resource must be taken as an order-of-magnitude approximation at best, an enormous number such as 500,000 TCFG is within the range of estimates and is a useful assumption for the volume of gas potentially present in hydrates. In addition to the large amount of methane that probably is present in gas hydrates, another noteworthy aspect of gas hydrates as a potential resource is their occurrence at very shallow depths, less than 3,600 feet below the sea floor and from 650 to 4,000 feet below ground surface in permafrost areas.

Another important resource aspect of gas hydrate layers is that they may form impermeable seals beneath which significant accumulations of gas may be trapped. Seismic reflection data off northern Alaska and off the Carolinas strongly suggest the presence not only of gas hydrates but also of low-velocity zones beneath the gas hydrate layers that probably contain gas.

The U.S. Department of Energy has sponsored a modest program of research by the USGS aimed at improving knowledge about the occurrence and character of gas hydrates in the permafrost area of the North Slope and at collecting information on gas hydrates worldwide.

COAL-BED METHANE

In Europe and in the Eastern United States, coal-bed gas has been produced and utilized in limited quantities for many years, and, recently, coal-bed gas has been produced from coal beds in the Western United States. Several areas in the United States, most notably the Black Warrior basin in Alabama and the San Juan basin in New Mexico and Colorado, are now producing commercial quantities of gas. A recent issue of the *Oil and Gas Journal* (September 8, 1986, p. 43) reports a single month's production of more than 1 billion cubic feet of coal-bed methane in Alabama, 14 percent of the State's total gas production; this gas was produced from 266 wells in seven fields. This production represents only a tiny

fraction of the potential of coal-bed methane. Coal-bed methane resources in the United States are estimated at 72 to 860 TCFG, and most estimates are between 300 and 500 TCFG. Potentially productive areas in the United States include all of the coal basins.

During early stages of coalification, coal beds are affected by microorganisms in a predominantly low-temperature environment. Methane, carbon dioxide, and traces of other gases are released, as well as large amounts of water. Temperature and pressure increase as coal beds are buried by continued sedimentation, and increasing quantities of methane and carbon dioxide and smaller quantities of nitrogen, oxygen, hydrogen, and the heavier hydrocarbons such as ethane, propane, and butane are generated. Although much of this gas either is lost to the atmosphere or migrates from the coal into adjacent rocks, large quantities are retained in the coal as free gas within joints or fractures in the coal or as adsorbed gas within the fine micropore coal structure. Gas contained in joints and fractures is more easily removed from the coal than is the more abundant adsorbed gas. The gas adsorption capability of coal increases with increasing coal rank. Coal-bed gas contains 90 to 99 percent methane and has a heat of combustion of 950 to 1,035 Btu per cubic foot. During the formation of 1 ton of coal, as much as 46,000 cubic feet of gas may be generated.

At the present time, coal-bed gas is produced from deep, unminable seams, from drainage of gas in advance of coal mining, and from drainage of gas from mined-out areas. Production rates are highly variable. Initial daily rates from some of the better producing wells are more than 1 million cubic feet per day, but rates in most wells are less than 250,000 cubic feet per day. Physicochemical factors affecting recoverability of coal-bed gas include coal rank, moisture content, gas adsorption capability, macropore and micropore structure, cleat (or fracture) development, type of organic matter, temperature, and pressure.

From the perspective of petroleum geology, coal beds have some advantages over conventional gas reservoirs. Geographic and stratigraphic occurrences of coal beds in the United States and elsewhere are relatively well known, and, because the coal beds are both the gas source and the gas reservoir, problems of gas generation and migration are less complex. These factors, in conjunction with drilling depths of generally less than 3,000 feet, reduce exploration and exploitation costs. Nevertheless, in commercial production of coal-bed methane, as in the mining of coal itself, an understanding of coal-bed geology and the original conditions of deposition of coal beds enhances the ability to predict continuity of beds, their gas content, and their fracture development, three important factors related to gas production. Detailed studies of the original organic matter and of the thermal maturation (coalification) level are particularly valuable in predicting

gas contents. It is important to obtain any information that could improve estimation of gas flow rates, and there is a dearth of information on the gas contents and gas flow characteristics of coal beds throughout the United States. In many areas, a knowledge of the ground-water geology is important because many coal beds are good aquifers, and the production of methane is commonly accompanied by large amounts of water that reduce gas production rates. This water may be acidic or alkaline, commonly is rather saline, and may require special considerations and expense for its environmentally sound disposal.

TIGHT GAS RESERVOIRS

In addition to gas produced by normal flow from permeable reservoir rocks, a major potential gas resource exists in reservoir rocks having such low permeability that the gas cannot be produced by using conventional engineering techniques (fig. 49). These so-called "tight" reservoir rocks generally are blanket or lenticular sandstones or chalky limestones and have permeabilities to gas of less than 0.1 millidarcy. The low permeabilities result either from fine grain size and tight packing or from cementation that has closed off much of the original pore space and the connecting passageways between pores. Most tight rocks are naturally fractured, and the fractures provide pathways that improve gas flow from the reservoirs.

Tight reservoir rocks containing significant potential resources of gas are in sedimentary basins both in a Rocky Mountain belt that extends from New Mexico

to Canada and in the South Central United States (fig. 50). Of the 20 basins known to contain such resources, the Piceance basin in Colorado, the Uinta basin in Colorado, and the greater Green River basin in Wyoming and Colorado are the most explored and have the greatest potential for early significant gas production. Some studies, such as one done by the National Academy of Science in 1976 and one conducted by the National Petroleum Council (1980), indicate that tight gas reservoirs have potential recoverable resources approximately equal to those of undiscovered conventional gas. The Rocky Mountain basins are estimated to contain in-place resources of perhaps 600 TCFG, and the remaining 17 basins probably contain an equal amount. If a recovery rate of 25 to 40 percent of in-place resources is assumed, the potential recoverable tight reservoir gas resource of the United States is 300 to 480 TCFG.

Production from tight gas reservoirs is achieved by hydraulically fracturing the rocks around a well. A water-based gel mixed with sand is pumped into the well under extremely high pressure to fracture the surrounding reservoir rocks, and the sand keeps the fractures open. Under ideal conditions, these fractures can extend as much as 2,000 feet outward from a well and provide new large surface areas from which the contained gas can flow. If the zone is effectively fractured, gas commonly will flow at a lower rate than it will from a conventional well but for a longer time.

Both exploration and production are more expensive in tight gas reservoirs than they are in conventional

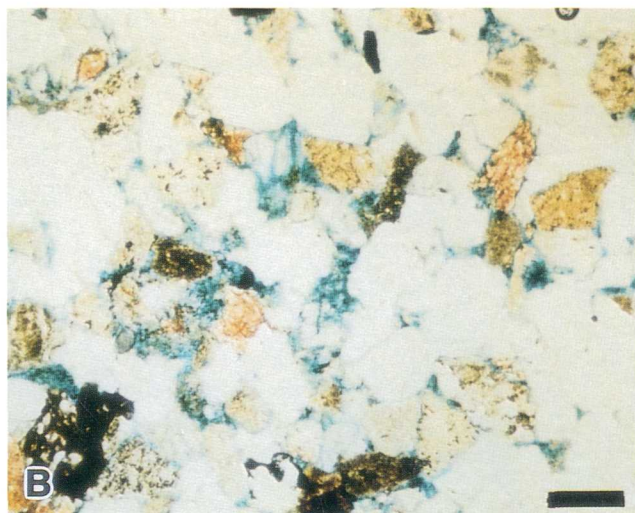
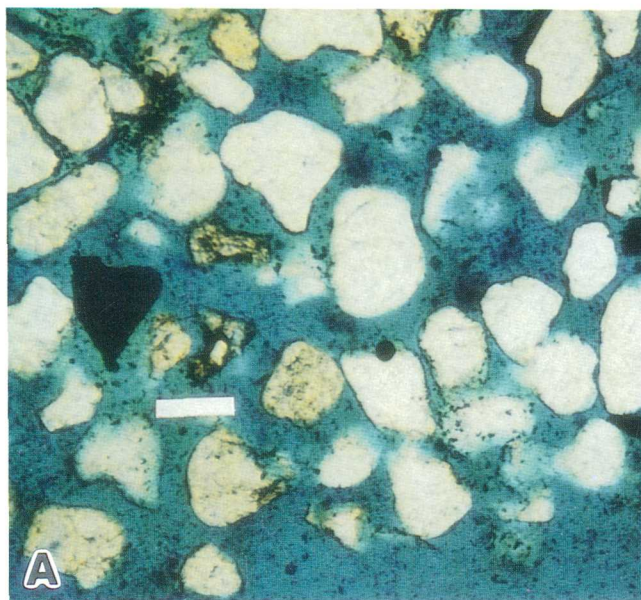


Figure 49. Photomicrographs of (A) conventional sandstone reservoir rock from the Cretaceous Muddy Sandstone in the Powder River basin of Wyoming and (B) low-permeability (tight) reservoir rock from the Cretaceous Mesaverde Group in the Piceance basin of Colorado. Pore spaces in both A and B are filled with blue epoxy. Bar scale is 0.2 mm. (Photographs supplied by C.W. Spencer.)

reservoirs. Geologic information on the occurrence of reservoir rocks and the depositional and postdepositional processes that formed them is particularly important. For example, most fluvial (river-deposited) sandstones are highly lenticular and have irregularly distributed reservoir characteristics. They do not fracture as well or as predictably as blanket sandstones deposited in nearshore marine environments. On the other hand, the more laterally continuous blanket sandstones typically have low porosity resulting from erratically distributed, postdepositional mineral grain solution and deposition. Reservoir rocks comprising blanket sandstone, siltstone, and chalk deposited in deeper marine environments have yet another set of rock properties that must be considered during exploration and production. These rocks are very fine grained, and their pores and interconnecting spaces are very small; as a result, they commonly have good porosity but low permeability.

Tight gas reservoirs are difficult to identify by using conventional seismic reflection exploration techniques, and an accurate knowledge of the environments of deposition of the reservoir rocks can help determine good targets for drilling. When a potential target reservoir is

drilled, conventional interpretive methods must be used very carefully, because tight formations are texturally and mineralogically different from conventional reservoir rocks. A knowledge of the continuity of reservoir rocks and their detailed physical, mineralogical, and chemical characteristics is critical in designing production methods that will not damage the formation by the plugging of pore connections resulting from the movement of fine-grained minerals or the swelling of clays, an increase in water saturation and a consequent reduction in the relative permeability to gas, and chemical interactions between additives and mineral grains. In addition, the distribution of both gas and water in the reservoir must be known before production begins.

A knowledge of the geologic factors described above may help determine if gas from tight reservoirs can be included in the energy resource base of the United States. In addition, government land use policies may be a critical factor in determining future resources, because most basins having the potential for gas in tight reservoirs are in the Western United States and contain large areas of Federal land. Current knowledge of the geology of potential reservoir targets is not sufficient to make informed resource assessments.

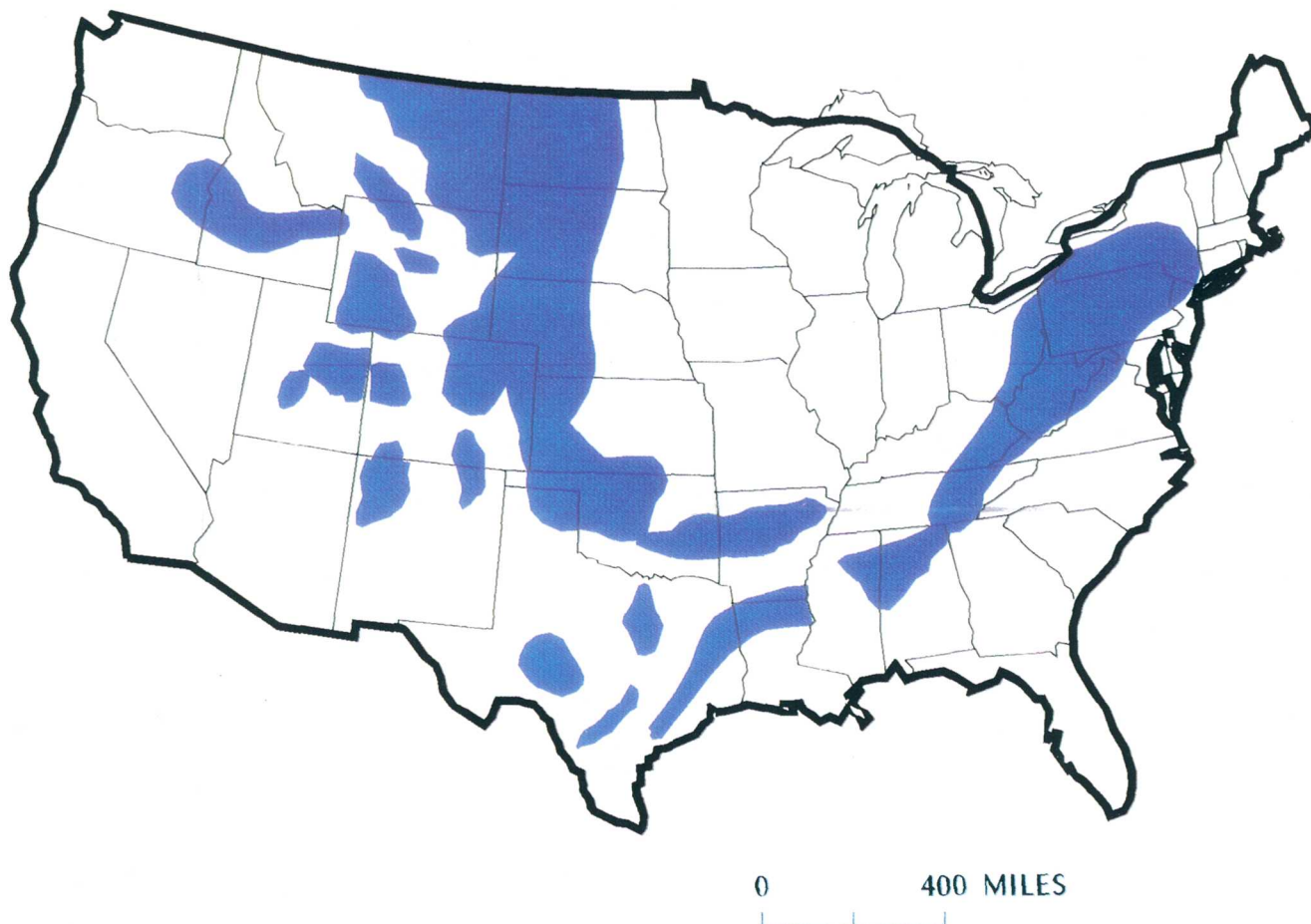


Figure 50. Basin areas in the United States containing tight reservoir rocks.

Focus: Detailed Studies of Tight Gas Reservoirs

USGS studies of tight gas reservoirs have been concentrated in areas where test well projects of the U.S. Department of Energy and of industry offer large amounts of geophysical data and drill-core samples for the target rocks: the Department of Energy's Multiwell Experiment site in Garfield County, Colorado, a second site in the Piceance basin about 30 miles from the Multiwell Experiment site, and an area of several wells on the Pinedale anticline in the Green River basin of Wyoming. Syntheses of the structural and stratigraphic geology in each basin were done to provide a framework for detailed observations at the well sites.

Tight gas reservoirs in the Piceance basin are fluvial and marine sandstones of the Cretaceous Mesaverde Group and fluvial sandstones of the lower Tertiary Wasatch Formation (Spencer and Keighin, 1984). Most of the detailed studies have been concentrated on rocks of the Mesaverde Group. The character of these rocks is quite variable and is dependent on the original environments of deposition. The sediments were deposited along the margin of a seaway in marine, delta plain, and stream environments. Deposits of these environments interfinger in a complex fashion and are difficult to distinguish by using conventional well log analysis techniques.

Each rock type has distinctive textural and mineralogical characteristics that result both from original differences in deposition and from subsequent postdepositional changes. Understanding the character of these reservoir rocks and their thermal history and organic-matter alteration levels is important in designing engineering approaches to gas recovery.

The need for better geologic information as a basis for both exploration and production of gas in tight reservoirs of the Piceance basin or any other basin has been well stated by Chancellor and Johnson (1986, p. 351, 357) in a report on cooperative industry-USGS research on five wells drilled in an area about 30 miles from the Multiwell Experiment site:

Based on production information to date, attempts at selecting intervals with comparatively better than average permeabilities using state of the art techniques were not successful. This study points out several important differences in the Mesaverde Formation/Group

between the area of the five wells and the MWX [Multiwell Experiment] site. Formation temperatures are higher and levels of thermal maturity are lower in the area of the five wells than at the MWX site. High formation pressures were encountered in the lower part of the Mesaverde Formation at the MWX site, while thus far, only near normal to slightly below normal pressures have been encountered in the Mesaverde Group in the area of the five wells....Development of the gas resource will depend on: (1) the development of economic methods to stimulate thick intervals without blockage of matrix permeabilities; and (2) methods to define areas or formation intervals where effective permeabilities are somewhat higher than average. It is also important to define where gas generation occurred in the past, and areas where significant rates of gas generation are occurring today....The traditional use of state-of-the-art geophysical log analysis and available geologic information in the selection of intervals to stimulate, has not resulted in improved deliverability rates. The identification of areas or formation intervals of higher than average effective permeabilities, may require a greater understanding of the regional geologic setting, including the environments of deposition, and the diagenetic postdepositional history.

Studies in the Green River basin have produced a picture of similar complexity. Porosity and permeability in tight reservoir rocks typically depend on dissolution of rock fragments and distribution of carbonate cements, neither of which appears to follow a pattern. Geochemical studies aimed at determining the source of the gas indicate that, as suspected, the gas came from coals and carbonaceous shales interbedded with the reservoir sandstones. Research on organic alteration, past and present basin temperatures, and gas generation has led to a partial understanding of reservoir overpressuring, including prediction of areas and depths at which overpressured gas reservoirs may occur.

GEOTHERMAL ENERGY RESOURCES

A vast amount of naturally occurring heat is stored in the Earth, but most of this geothermal energy is too deeply buried and too dispersed to be tapped for human use. Geothermal energy can be exploited only where it occurs in high concentrations at accessible depths, like concentrations of other natural resources such as ore deposits and petroleum accumulations. Currently, both high temperature at drillable depth and sufficient water or steam to transport the thermal energy to the surface are needed to exploit geothermal systems for electrical production or direct-heat use.

Geothermal energy currently provides only about 0.2 percent of U.S. electrical needs. However, although use of geothermal energy in the United States is dwarfed by use of traditional fossil fuels, hydropower, and nuclear energy, USGS studies indicate that the geothermal resources of the United States are large. During the next decade, development of geothermal energy probably will remain focused on hydrothermal (hot water or steam in the ground) resources that could provide a few percent of the electrical generation capacity in some Western States. Great potential exists, however, for growth of geothermal utilization in direct-heat uses of lower temperature resources.

In considering geothermal energy, it is important to distinguish between the amount of geothermal energy stored in the ground and the lesser amount that can be extracted and recovered at the surface. The **accessible geothermal resource base** is the thermal energy in rocks and fluids at depths shallow enough to be reached by drilling in the foreseeable future, whereas the **geothermal resource** is that part of the accessible resource base that might be extracted economically at some future time, given reasonable advances in technology and economic favorability. Geothermal projects on line or under construction reflect development of geothermal **reserves**, that part of the geothermal resource extractable at a cost currently competitive with other energy sources. For long-term planning of energy policy, the magnitude of the resource is of greatest importance.

The geology of geothermal systems is related to resource development in the following ways:

- Both the geologic controls and the effects of sustained production and accompanying injection of spent fluids on the natural life expectancy of a geothermal system are not completely understood.
- The discovery of geothermal systems not yet identified because they lack obvious surface features such as hot springs, as well as the resource characterization of known hydrothermal systems for which reservoir temperature and volume currently may be underestimated, requires geologic information. Undiscovered geothermal resources are estimated to be several times greater than identified resources, and significant long-term growth in geothermal resource development depends on improved techniques for locating and evaluating the undiscovered component.
- Geothermal development has been limited to economically drillable depths, generally less than 2 miles. Deeper parts of geothermal systems can be tapped for energy recovery when technological advances and economic factors permit, and geologic characterization of these root zones will be necessary.

GEOTHERMAL SYSTEMS AND THEIR DISTRIBUTION

Almost all development of geothermal resources has exploited hydrothermal convection systems in which the buoyant movement of hot water through rock pores and fractures concentrates thermal energy into restricted volumes or reservoirs (fig. 51). In the most common hydrothermal convection systems, hot pressurized water enters a drill hole and flashes in part to steam. This water-steam mixture flows up the well to the surface, where steam and water are separated; steam then is routed to turbines to generate electricity, and unwanted water is injected back into the ground. In the much less common vapor-dominated systems, steam is the predominant fluid phase at depth, and dry steam can be produced at the wellhead without the need to separate and dispose of large volumes of water.

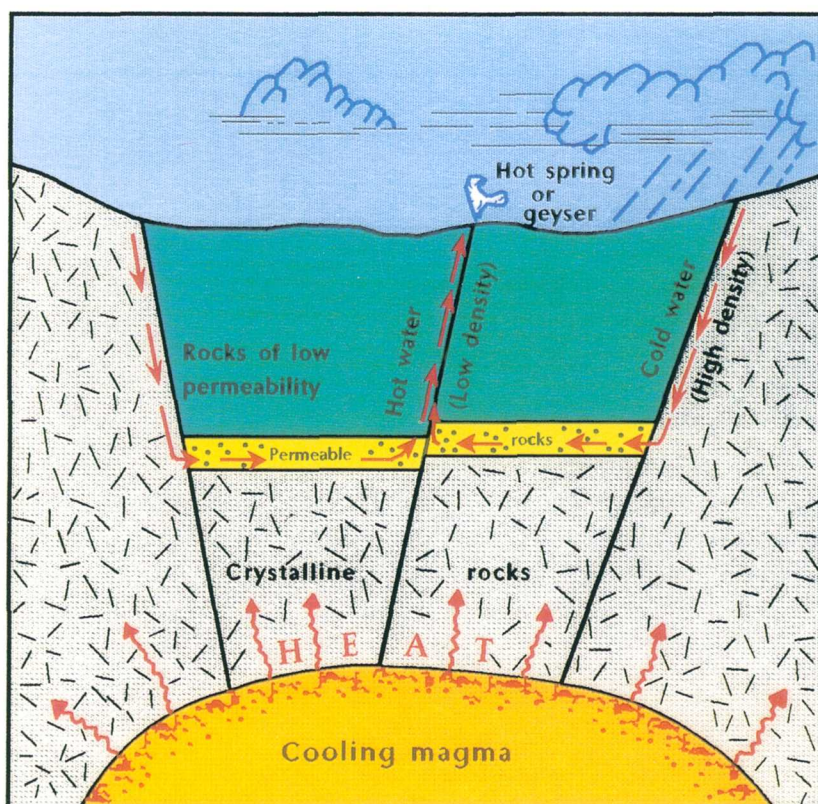


Figure 51. Schematic cross section of a high-temperature hydrothermal system. Modified from White (1973, p. 76).

Although hydrothermal systems having temperatures of less than about 200 °C currently are not economical for separating steam from water for use in turbines, geothermal water from such systems can be used to heat a secondary fluid such as freon, which in turn drives turbines. Hydrothermal systems having temperatures of 40 to 100 °C can be used for direct applications such as space heating and industrial drying.

Most high-temperature (greater than 150 °C) geothermal resources currently being exploited are associated with regions of recent volcanism, in which bodies of magma (molten rock) provide sources of heat and deeply penetrating faults foster circulation of water to depths where temperatures are high. These regions of high heat flow typically are along boundaries between the Earth's tectonic plates, at hot spots within plates, or along rift zones (fig. 52). In the United States, high-temperature

geothermal resources are in the Western States, and intermediate- (90–150 °C) and low-temperature (less than 90 °C) resources are more widely dispersed (fig. 53).

In 1978, the USGS estimated the identified resource in 215 known hydrothermal systems having temperatures greater than 90 °C and depths less than about 2 miles to be about 400 Quads (quadrillion Btu); the undiscovered resource was estimated to be 2,000 Quads. The part of the identified resource having temperatures greater than 150 °C is equivalent to 23,000 megawatts of electricity for a 30-year period. In 1982, the USGS evaluated 1,161 low-temperature (less than 90 °C) systems and estimated a resource of 87 Quads. Approximately 70 percent of this energy is contained in 42 systems in the Central United States, including aquifers of significant lateral extent, such as those that extend under much of Montana, North and South Dakota, and Wyoming.

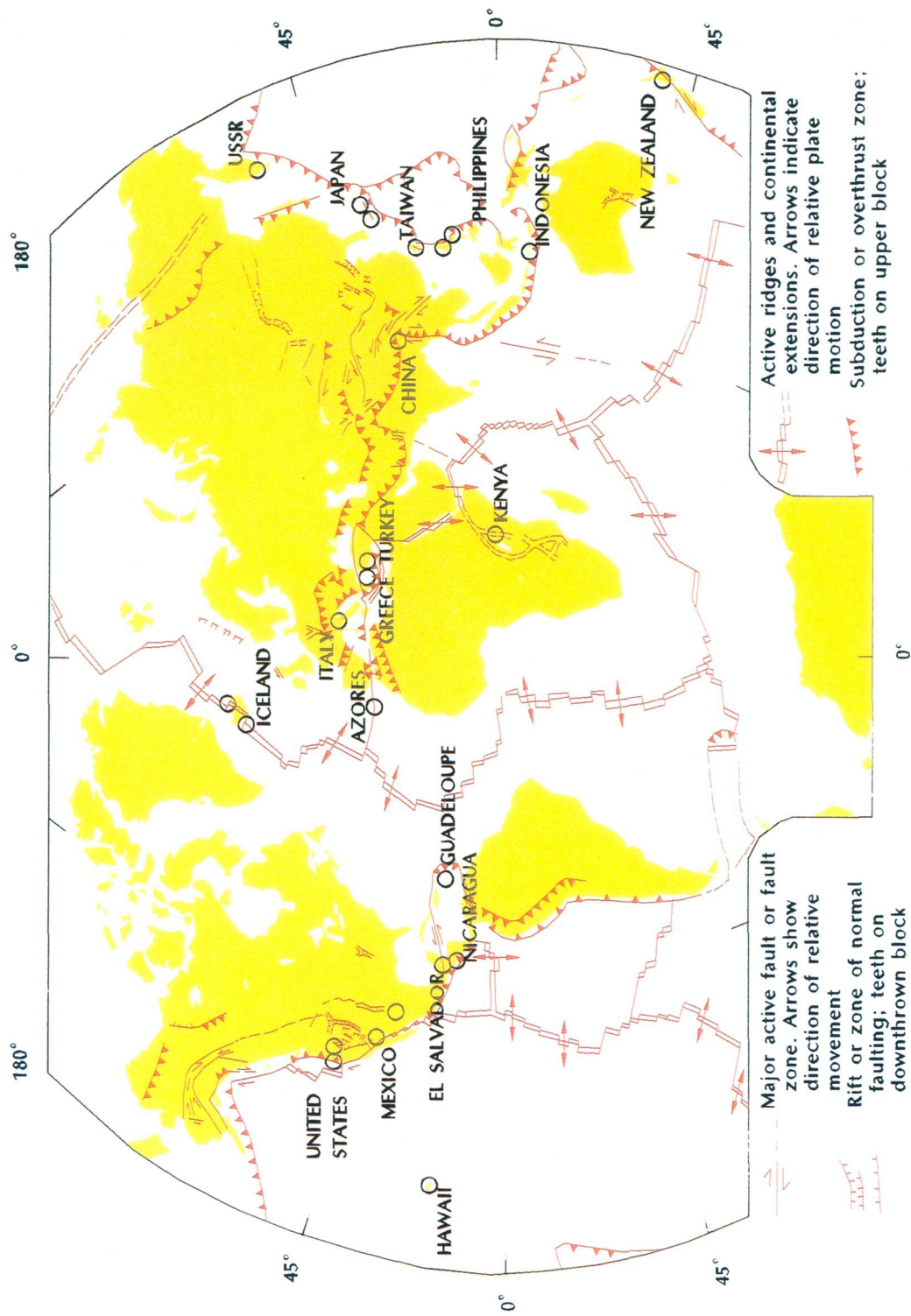


Figure 52. World distribution of geothermal fields from which electricity is being produced (open circles).

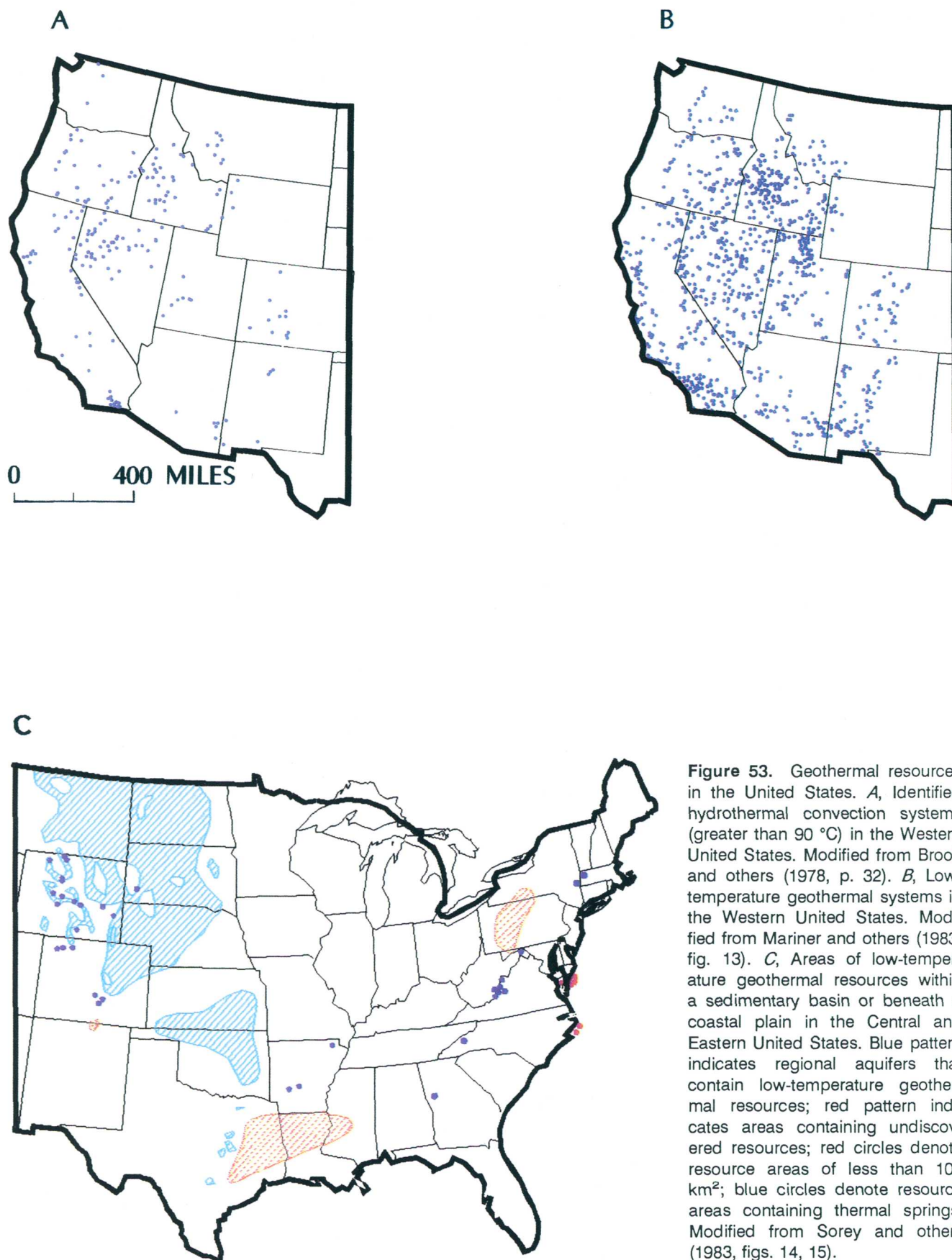


Figure 53. Geothermal resources in the United States. *A*, Identified hydrothermal convection systems (greater than 90 °C) in the Western United States. Modified from Brook and others (1978, p. 32). *B*, Low-temperature geothermal systems in the Western United States. Modified from Mariner and others (1983, fig. 13). *C*, Areas of low-temperature geothermal resources within a sedimentary basin or beneath a coastal plain in the Central and Eastern United States. Blue pattern indicates regional aquifers that contain low-temperature geothermal resources; red pattern indicates areas containing undiscovered resources; red circles denote resource areas of less than 100 km²; blue circles denote resource areas containing thermal springs. Modified from Sorey and others (1983, figs. 14, 15).

GEOHERMAL ENERGY IN THE NATIONAL ENERGY MIX

The United States leads the world in geothermal electricity-generating capacity. In 1986, 17 countries generated 4,733 megawatts of electricity from geothermal sources. In mid-1986, the geothermal capacity in California, Hawaii, Nevada, and Utah was approximately 2,000 megawatts (table 6), and projects under construction or planned could increase this capacity to as much as 3,300 megawatts in the next several years.

Table 6. Geothermal powerplants in the United States as of June 1986

State	Field	Capacity, in megawatts
California-----	The Geysers	1,788
	Imperial Valley	
	East Mesa	12.5
	Salton Sea	44.5
	Heber	94
	Wendell-Amadee	.6
Hawaii-----	Mammoth Lakes	7
	Puna	3
Nevada-----	Wabuska Hot Springs	.6
	Beowawe	17
	Steamboat Springs	5.5
	Desert Peak	9
Utah-----	Roosevelt Hot Springs	20
	Cove Fort	2.7
Total installed capacity-----		2,004.4

Most geothermal capacity in the United States is at The Geysers field in northern California. This large vapor-dominated system has been developed since 1960 and consists of 19 separate powerplants having a capacity of almost 1,800 megawatts, enough to satisfy the electricity-generating needs of San Francisco and Oakland.

Direct-heat applications of geothermal energy for space heating, agriculture, aquaculture, and industrial processes are at hundreds of locations in the United States and supply about 210 megawatts of thermal energy. Identification of many areas containing low-temperature geothermal systems indicates large potential growth for this resource.

RESOURCE ASSESSMENT

A resource assessment is a statement made at a specific time and using a given data set and certain assumptions concerning economics and technology. Both the data set and the assumptions can change rapidly, and any assessment should be periodically updated. Geothermal assessments especially need to be revised regularly,

because exploration and development are rapidly increasing and because the worldwide energy situation is in a state of flux as countries try to come to grips with finite fossil fuel resources, environmental effects, nuclear waste disposal, and other issues.

Today's developed geothermal reserves represent only a fraction of the estimated geothermal resource in the United States. In 1975, the USGS completed the first national geothermal assessment based on a well-documented methodology and constrained by specific data on the chemistry and physics of geothermal systems; in 1978, it updated this assessment, using a large body of new data. In 1982, the USGS published the first quantitative assessment of low-temperature geothermal resources, and it is now refining the 1978 estimate of the geothermal resources of the Cascade Range, an active volcanic belt extending about 740 miles from British Columbia into northern California.

GEOLOGIC RESEARCH AND EXPLORATION FOR HYDROTHERMAL RESOURCES

Exploration for geothermal energy usually begins with the selection of geologically favorable terranes, such as those containing hot springs and (or) young volcanic rocks. Several volcanic fields have been intensively studied as part of the USGS Geothermal Research Program: The Geysers–Clear Lake, Long Valley, and Coso fields in California; Newberry and Mt. Hood volcanoes in Oregon; the San Francisco Mountains in Arizona; Yellowstone National Park; the Snake River plain in southern Idaho; and the Cascade Range of Washington, Oregon, and northern California. These studies have greatly increased our knowledge of the processes of mass and energy movement within magmatic and associated hydrothermal systems.

Seismic techniques help characterize geothermal systems. Timing the passage of seismic waves from distant earthquakes can locate zones of partially molten rock within the Earth's crust. USGS studies have determined that molten material apparently underlies volcanic fields at Long Valley, The Geysers–Clear Lake area, and Coso in California, at Yellowstone National Park, and at Roosevelt Hot Springs in Utah. Another technique maps the paths of seismic waves generated by controlled explosions and has been used to delineate the structure of the crust beneath the Imperial Valley, an extensive geothermal area in southern California that has few surface hydrothermal features.

Geochemical techniques pioneered by USGS scientists allow subsurface temperatures within a geothermal reservoir to be estimated from the chemistry of thermal

water that leaks to the Earth's surface as hot springs or that is produced from shallow drill holes. These techniques greatly increase the chances of finding a high-temperature hydrothermal system before and during drilling and are applied worldwide as standard exploration tools. The USGS also has helped develop a variety of geophysical methods to map the lateral and vertical extent of a hydrothermal system in the shallow crust.

Hydrologic research provides information on the natural state of hydrothermal reservoirs and their behavior under production. Hydrologic analysis was a key element in the recent USGS assessment of low-temperature geothermal resources. Hydrologic studies are important in understanding hydrothermal convection systems in Nevada, at Newberry volcano in Oregon, and at Lassen Volcanic National Park and Long Valley in California, and they are critical in understanding the enigmatic springs of the Cascade Range in Oregon. Computer-assisted modeling is useful in estimating the rate and duration of production from a reservoir.

Research drilling is a relatively expensive and therefore infrequently used tool, but it allows direct testing of models of subsurface conditions. In 1981, the USGS drilled a 3,057-foot-deep hole at Newberry volcano and discovered a very high temperature zone (265 °C) beneath a 1,970-foot-thick zone of cooler ground water. The temperature-depth profile from the hole gives credence to the hypothesis that deep hydrothermal systems in the Cascade Range are blanketed by percolating snowmelt and rainwater and thus hidden from surface expression. Other hypotheses concerning both the deep parts of geothermal systems where mineralization may be occurring and the coupling of magma bodies and hydrothermal convection systems remain untested by surface and shallow measurements. Accordingly, the USGS, in conjunction with other Federal agencies, is promoting programs to drill into hotter and deeper levels of geothermal systems. In one of these programs, the U.S. Department of Energy recently has drilled to a depth of 10,564 feet in the Salton Sea field of California's Imperial Valley.

Focus: Geothermal Energy in California

Geothermal energy is an important part of California's total energy mix, providing about 5 percent of the State's electricity in 1986. In 1972, the USGS began a long-term multidisciplinary research program at The Geysers in northern California as one of the first projects of the newly funded Geothermal Research Program. This research effort has deciphered the volcanic and tectonic history of the area and inferred the location and properties of a crustal magma body (heat source for the hydrothermal system). Geochemical studies of the thermal waters, together with geologic and geophysical studies, were used to define the subsurface boundaries of the geothermal field. Seismic monitoring has established that small-magnitude earthquakes are induced by geothermal production but currently are not a hazard. Both seismic

monitoring and geochemical studies are continuing to determine the response of the natural system to sustained production.

The Imperial Valley, southeast of Los Angeles, also contains substantial geothermal resources. Recent development of several hot-water systems has demonstrated the technical and economic feasibility of generating electricity from geothermal fields having characteristics less favorable than those of The Geysers. Studies by the USGS at the Salton Sea field have helped decipher the geologic effects of hot saline brines in the geothermal system interacting at elevated temperature and pressure with sediments of the Colorado River delta. An extensive seismic survey of the Imperial Valley has delineated the subsurface structure of this unique region.

URANIUM RESOURCES

Although nuclear power provides about 13 percent of the electricity consumed each year in the United States, its future is clouded by problems: increased timeliness and sharply increased costs for plant construction, regulatory and legal delays, and, above all, real and perceived issues of nuclear safety. Projections of modest levels of growth in electricity demand indicate a need either to start building more nuclear plants in the 1990's or to dramatically increase fossil-fuel (most likely coal) electricity-generating capacity. The latter option has its own problems, such as increased amounts of carbon dioxide in the atmosphere (the "greenhouse effect"), acid rain from sulfur emissions, and the resource availability issues discussed elsewhere in this volume.

The many problems surrounding nuclear energy have sharply curtailed domestic production of uranium. Most of the mines active during the early 1980's are now closed because of the precipitous drop in the demand for uranium and in its price. Competition from cheaper imported uranium has also put pressure on the domestic uranium mining industry.

Some exploration and mining activities persist despite market conditions. Two types of uranium deposits appear to offer economic potential at this time—young surficial deposits (see Focus, "Surficial uranium deposits," p. 74) and mineralized breccia pipes—and USGS

research is being directed toward understanding such ore occurrences. In addition, continuing analysis of information gathered during the uranium boom of the late 1970's and early 1980's is now producing significant new insights into the process of uranium mineralization and the mechanisms of formation of some of the most important uranium ore deposits in the United States (see Focus, "A new model for uranium mineralization in the San Juan basin of New Mexico," p. 76). Research continues on uranium geology in order to refine existing knowledge about the uranium resources of the United States, resources that will be needed if nuclear energy assumes renewed importance in the future.

The USGS is the repository of data from the \$300 million U.S. Department of Energy National Uranium Resource Evaluation (NURE) program. These data are of value in many regional geologic and resource investigations. A recent application of the NURE data and expertise in uranium geology is connected with the growing effort to assess and predict the occurrence and hazard potential of radon gas. Radon is a daughter product of the radioactive decay of uranium, and knowledge of the geologic habits of uranium underlies an understanding of radon in the geologic environments of rocks, soils, and ground water. This active research by the USGS is capitalizing on years of study of uranium geology and takes full advantage of the NURE data.

Focus: Surficial Uranium Deposits

Scientific studies and exploration currently are focused on surficial uranium deposits, a type of uranium accumulation that was recognized only a few years ago. These deposits typically have formed within the last 12,000 years and are so young that radioactive decay has not yet produced enough daughter products to permit detection by using normal gamma-ray radiometric surveys. Instead, the deposits must be located by sampling and chemical analysis.

These young uranium deposits commonly are found in terranes containing granitic rocks from which surface waters can leach uranium. As the mobile uranium moves downslope with shallow ground water, it comes in contact with organic materials along small stream drainages and is precipitated or absorbed from solution. Significant concentrations of uranium have been found in boggy meadows along valleys at the drainage divides between streams, in swamps impounded by beaver dams, in bogs around lake margins, and in swamps or meadows in flood plains and cutoff river meanders. The distribution of the uranium in these young deposits depends both on the

water flow and on the permeability of the interlayered peat and stream sediments. In areas where the principal flow of surface and shallow ground water is down the axis of the valley, uranium is concentrated at the upstream edges of valley bogs and swamps. In valley settings where ground water wells up beneath the organic-rich environment, uranium is concentrated at the bottom of organic-sediment columns. In spring-fed meadows along valley slopes, uranium is most concentrated near the surface, and its concentration decreases downward through the peat and sediments.

One surficial deposit has been mined along Flodelle Creek in northeastern Washington State. The climate, water flow, source rocks, and peat accumulation pattern in that area are highly favorable for the formation of surficial uranium deposits. The Flodelle Creek deposit probably contains about 1 million pounds of uranium oxide and has an average grade of 0.08 percent, similar to the grade of sandstone-hosted uranium deposits long mined in the United States. Similar deposits have been found in relatively similar geologic settings in northeast-



Figure 54. Infrared aerial photograph of the Carson Range, just east of Lake Tahoe. Bright red delineates areas of deciduous vegetation along stream bottoms, along which both organic matter and uranium leached from rocks of the Carson Range have accumulated. Twenty-two surficial uranium deposits have been found along these drainages.

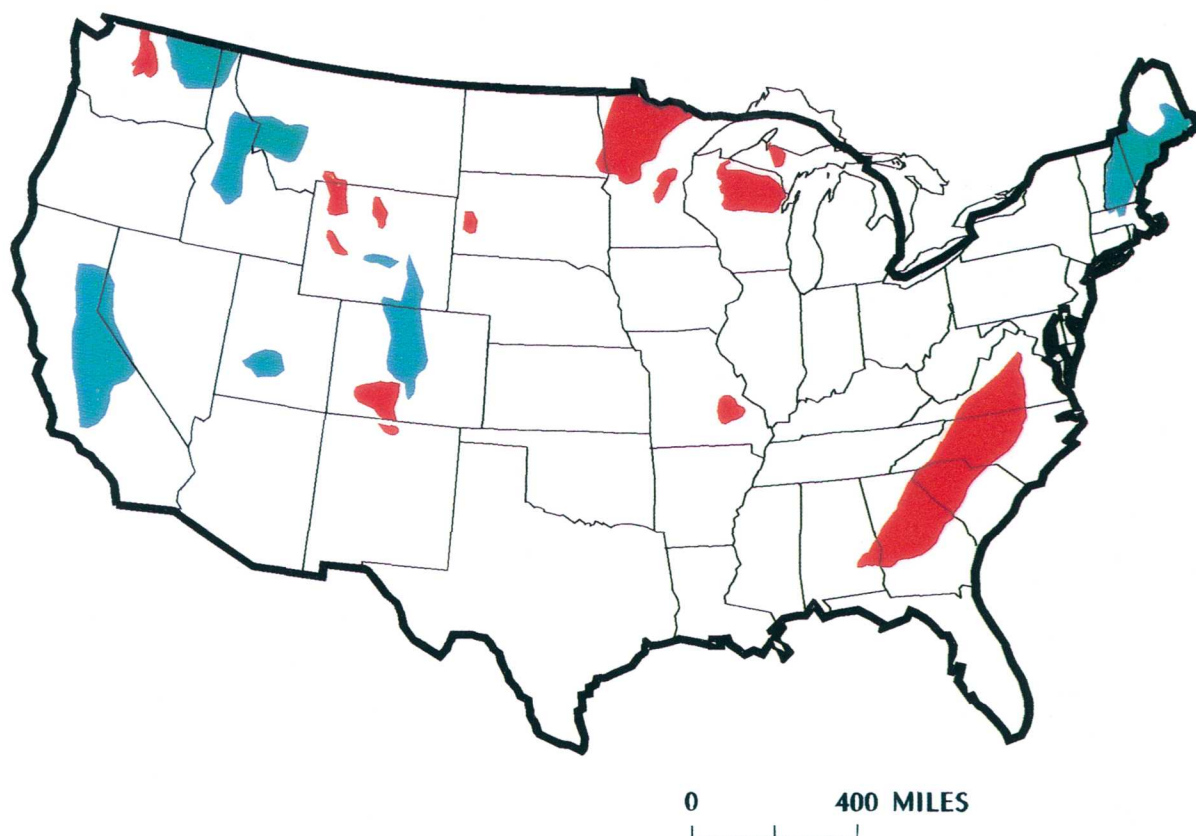


Figure 55. Surficial uranium deposits in the United States. Blue indicates areas known to contain surficial uranium deposits; red indicates areas believed to contain surficial uranium deposits.

ern and northwestern Washington State, north-central Idaho, the Sierra Nevada in California (fig. 54), the Colorado Front Range, and Maine (fig. 55).

The radioactivity of surficial uranium deposits is relatively low. Health hazards in mining are minimal, and mining spoils generally can be returned directly to the mine without treatment. The ore occurs as loose material at the surface and can be removed by using light equipment and, consequently, at low cost. The ore is porous and permeable, and little preparation is required before direct extraction of the uranium; some ore may be amenable to in-place leaching techniques. In addition, the

deposits are suitable for small-scale mining and milling operations. Deposits typically cluster along a stream course, and ore from individual deposits can be fed to a centrally located mill.

Uranium is a highly mobile element; its poisonous effects are similar to those of arsenic, and it is a carcinogen after long-term accumulation in the human body. Uranium moving in ground or surface water, either before precipitation by organic matter or after remobilization from its precipitate habitat, can be of environmental concern in populated areas. Continuing USGS studies of surficial uranium deposits are aimed at both the resource and the hazard aspects of uranium.

Focus: A New Model for Uranium Mineralization in the San Juan Basin of New Mexico

Key new field and laboratory studies of uranium deposits and their associated rocks and years of observations and insights attained by many geologists have been used to construct a conceptual model explaining the location and origin of the ore deposits in the most important uranium district in the United States (Turner-Peterson and Fishman, 1986). A basin analysis method was used to achieve an understanding of the depositional setting of the ore-host sandstones and the overlying volcanic ash-rich sedimentary units and of the probable source of the organic material that acts as a trap for the uranium.

The Late Jurassic (about 140 million years ago) tectonic setting of the San Juan basin in northern New Mexico was integral to ore genesis. Uplift in a magmatic arc region hundreds of miles west of the Jurassic basin established the stream gradients necessary to deliver sediment to the subsiding basin and resulted in deposition of the host sandstones of the Westwater Canyon Member of the Morrison Formation. Throughout Morrison time, volcanism in the arc region supplied abundant volcanic ash. This ash accumulated and was preserved most abundantly in a saline-alkaline lake atop the Westwater Canyon sandstones. It formed the Brushy Basin Member, and its chemistry was a key element in controlling pore-water composition in the Morrison Formation.

The ore occurs as a pore-filling uranium-organic matter mixture in the sandstones, and the main ore control is the organic material (fig. 56). Detailed examination of the rocks indicates that the organic material was introduced into the host sandstones soon after deposition and then served to precipitate uranium from groundwater percolation through the rock. Several lines of evidence indicate that organic material in ore zones was derived from humic material, and the source of this organic material is the main concern in ore genesis.

Defining the depositional environments of the Brushy Basin Member constrained reconstructions of the geometry of the Jurassic basin and also explained ore-related alteration patterns in Morrison sandstones. These alteration patterns in turn aided reconstruction of ore-related hydrology and pointed to the Brushy Basin Member as a source for the organic material. The geometry of the Jurassic basin can be accurately inferred because saline-alkaline lakes develop only in closed-basin settings and because mapping of late-growth (postdepositional) mineral distributions in the lake sediments has defined the paleolake basin. The Jurassic lake extended well north of the present-day San Juan basin margin. Organic-bearing pore water descending from these paleolake sediments altered underlying sandstones, and mappable lateral trends in these altered areas are parallel with lateral

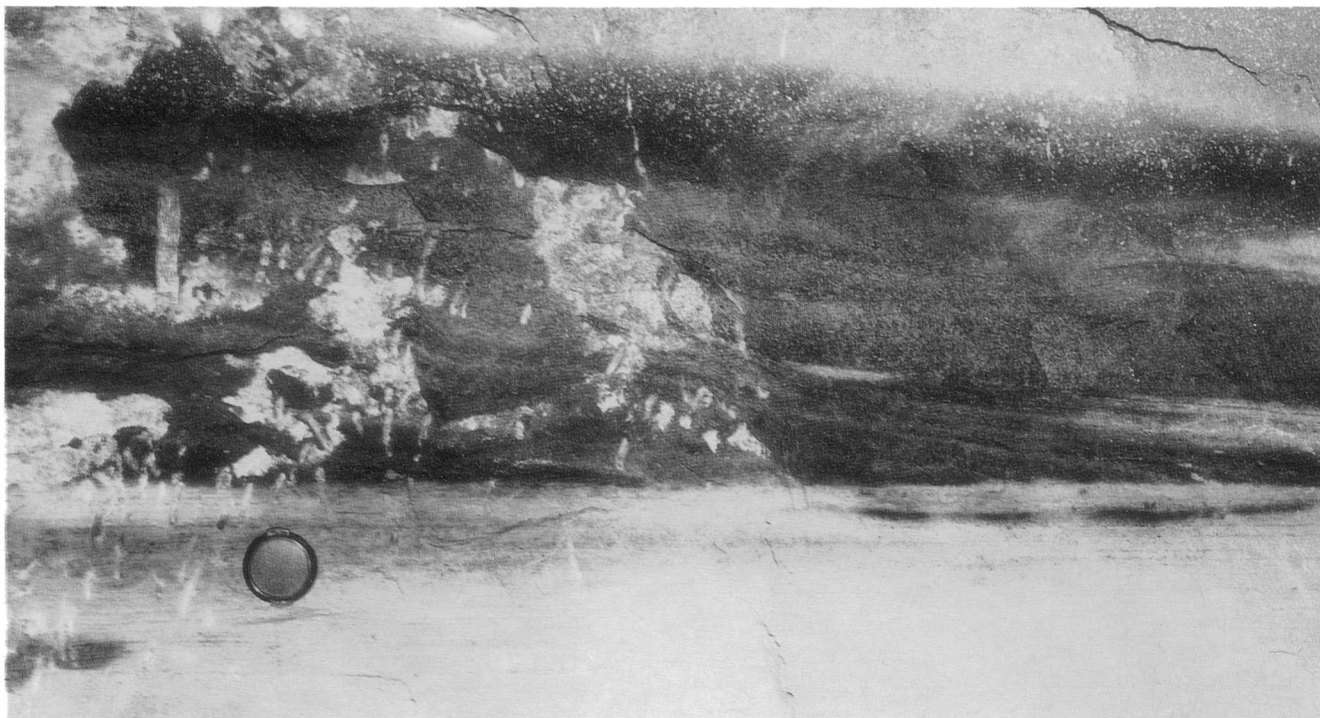


Figure 56. Organic-rich uranium ore (black layer) in sandstone of the Westwater Canyon Member of the Morrison Formation in the San Juan basin of New Mexico.

changes observed in late-growth mineral occurrences in the overlying lake sediments. Mineralogical changes in the ore-host sandstones reflect this downward movement of pore fluids. Alteration of iron oxide grains can be directly related to movement of organic-bearing fluids, and detailed mapping of the altered mineral grains indicates that the mudflat-deposited sediments of the Brushy Basin Member are the source of these fluids. For this reason, ore is restricted to sandstones that received fluids

from the mudflat-deposited part of the Brushy Basin Member (fig. 57).

The conceptual model provides a new picture of Morrison basin sedimentation history and an explanation for the source of the organic material that trapped the uranium. This new understanding of the process of mineralization explains the geologic control of the location of uranium deposits and thus offers a guide for future exploration.

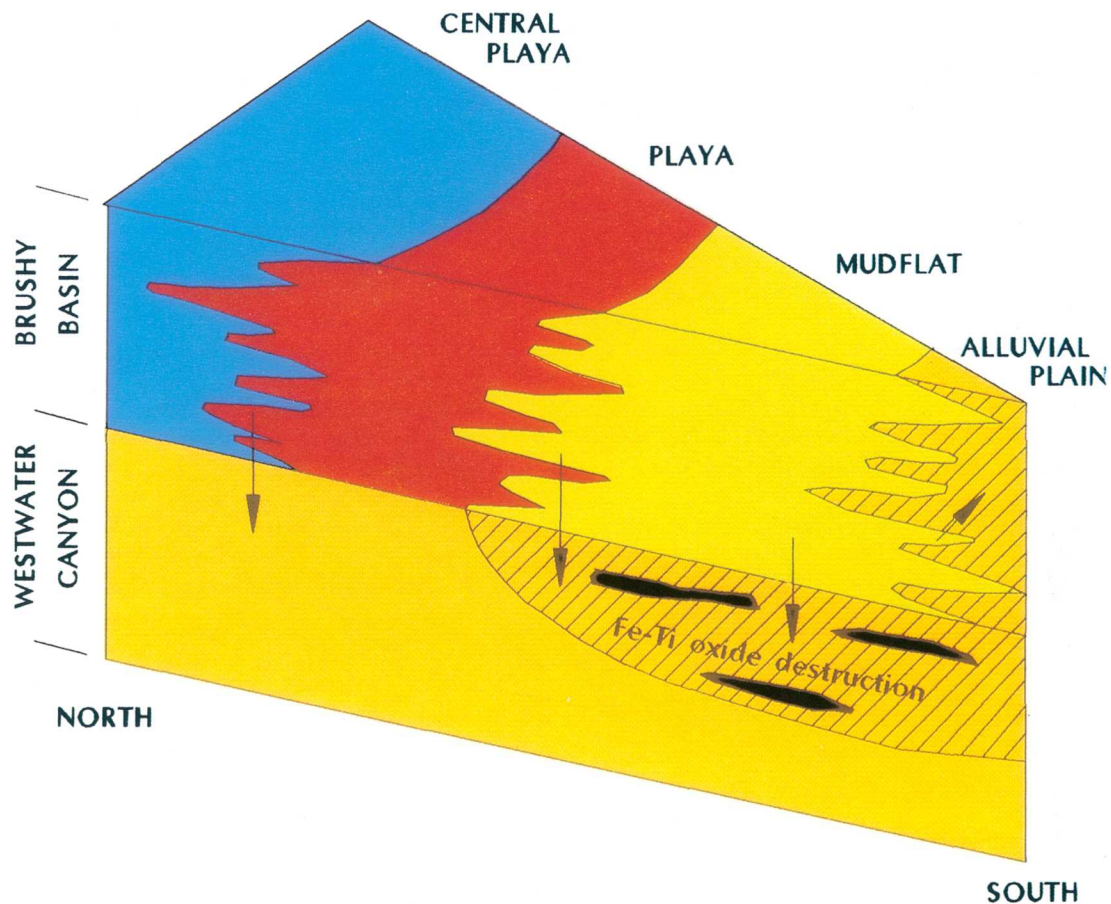


Figure 57. Distribution of sedimentation zones in the Brushy Basin Member of the Morrison Formation marking different environments in a saline-alkaline playa lake of Jurassic time. Fluid moving downward from the mudflat zone (arrows indicate direction of fluid flow) altered or destroyed Fe-Ti (iron-titanium) oxide minerals in the underlying Westwater Canyon Member and created the conditions necessary for the precipitation of uranium in ore deposits (black lenses) in the San Juan basin of New Mexico. Modified from Turner-Peterson and Fishman (1986).

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