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Enhanced Recovery of Crude Oil

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With domestic supplies of crude oil decreasing and imports costing more, the search for new technologies to increase recovery efficiency escalates

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Now, when production of domestic crude oil in the United States is falling and the probability of finding new oil is dwindling, attention is turning to methods of increasing recovery from known oil fields—that is, to the development of enhanced recovery technology. Newly developed technology has already begun to influence and increase the supply of domestic crude oil, particularly in California, but there is a definite limit to the economic feasibility of such additional recovery, which is set by the physical characteristics of the reservoirs and their crude petroleum fluids.

The overall recovery of crude oil from reservoirs in the U.S., using proven, conventional technology, is now estimated at 148 billion barrels, or 32%, of the estimated 460 billion barrels originally in them. Of this, 121 billion barrels, or 82%, had already been produced by the end of 1979. If we could increase the recovery rate to 42%, say, the present reserves of the U.S. would be more than doubled. This would put off the demise of the age of petroleum in the U.S. for another decade, but more important, it would provide time for society to plan orderly changes with respect to its fuel supplies. All enhanced recovery processes have a common goal: to increase the rate of flow of crude oil within the porous reservoir rock to economic levels.

Of the oil currently considered recoverable, some 20% had already been discovered by 1920, over a third of it in California. The two decades following World War I saw finds of great importance in Texas and Louisiana, and by 1940, 60% of the nation's now known recoverable oil—88 billion barrels—had been discovered. After World War II, the previous rate of discovery could not be maintained, despite the major find of Prudhoe Bay—the one supergiant field in the Western Hemisphere with approximately 10 billion barrels of recoverable oil. Despite an intensified exploration effort and growing expertise, it is increasingly difficult to find new, significant reserves in the U.S. (see Fig. 1).

In recent years, extensions and revisions of estimates of reserves in old fields—about 1.2 billion barrels per year—and the discovery of small fields—about 300 million barrels per year—have limited the annual decline in reserves in the U.S. to about 1.5 billion barrels. Nevertheless, oil reserves at the end of 1979—27 billion barrels—are now lower than at any time in the past three decades. Even if the trend of positive revisions and minor discoveries could be maintained, the nature of the reservoir production process would cause oil production in the U.S. to fall to half its present value before the turn of the century (see Fig. 2). Only the discovery of numerous giant and several supergiant fields can reverse this trend. However, since huge fields are usually the first to be found when a basin is explored, and since they contribute 65% or more of the oil produced by those basins (see, for example, Root and Drew 1979), the prospects for future discovery of such fields in the U.S. are not great, given the nature and the small number of still unexplored basins. The importance of enhanced recovery is thus apparent.

Formation and production of oil

In order to assess the potential of attempts to enhance oil recovery, it is necessary to understand how and under what geological conditions oil is formed, as well as how it is produced. Oil has its origin in organic debris—remains of dead organisms, probably algae for the most part—that accumulates in shallow seas and that is then entrapped in the silts and clays brought down to the seas by the rivers cutting through the continents. Over the years, layers of such sediments pile on top of one another and sink to lower and lower depths. As a result of burial, the temperatures and pressures to which these layers are subjected increase, and the organic material anaerobically decomposes into hydrocarbons. The liquid hydrocarbons that are produced are less dense than the interstitial water and are hence buoyed up and rise until they either encounter a barrier or escape to the surface of the earth. Oil

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that escapes is quickly oxidized or consumed by microorganisms.

Most oil is trapped in anticlinal folds beneath strata of shale, dense salt, anhydrite, or other impermeable material. Some very large accumulations of oil are found in stratigraphic traps formed when a layer of permeable sediment changes laterally to an impermeable sediment; still others are found in the traps formed where porous rock is sealed by a fault. If the seal on a reservoir is breached by erosion, the trapped oil will either escape or be converted to a bitumen through partial evaporation of its more volatile constituents. The great Athabasca bituminous sands of Alberta—the largest single accumulation of petroleum in the world—were perhaps formed in this manner.

Oil accumulates under pressure, which, in most cases, is hydrostatic. When the rate of sediment deposition is very rapid, however, equilibrium with the hydrostatic environment is not maintained, and the pressures under which the oil accumulates approach those of the lithostatic, or rock, overburden. It is the pressure differential between the fluids in the reservoir and the bore hole drilled into it that causes the oil to flow into the bore.

As the pressure in the reservoir decreases, gas is released from solution, thereby causing an increase in the total volume of reservoir fluids, some of which must flow out of the reservoir into the bore hole. Keeping the gradient in the bore hole low, artificially (for example, by pumping) if necessary, promotes the spontaneous flow of oil. The free gas is immobile at first, because the individual gas bubbles are not connected, and therefore only oil, saturated with gas, flows out of the reservoir. As more and more gas is released within the reservoir, a critical saturation is reached at which the gas phase becomes mobile; because it is far less viscous than oil and the saturation is increasing, the gas immediately begins to flow. As the flow of gas increases, the pressure in the reservoir decreases, owing to fluid withdrawal, which leads to a steady decline in oil production until the economic limit is reached (Fig. 3).

The economic limit is the production rate at which the value of the oil pro-

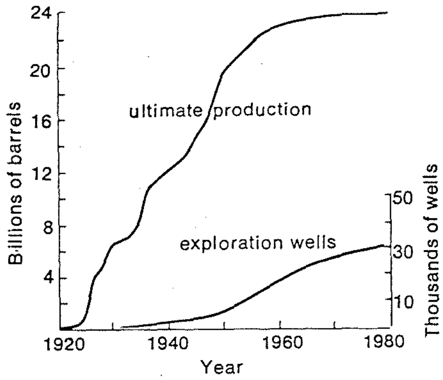


Figure 1. Immediately after the initial discovery of crude oil in west Texas and southeast New Mexico—the richest oil province in the U.S.—tremendous reserves were discovered, using clues from surface geological studies. As the rate of discovery waned, there was an exponential increase in the number of wildcat exploration wells drilled, but this failed to halt the decline.

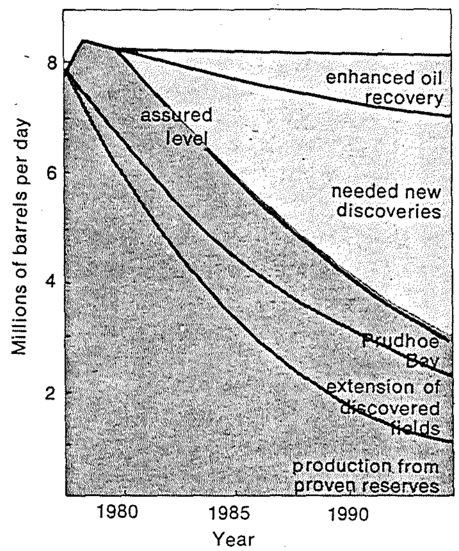


Figure 2. In order to maintain the present level of oil production in the U.S., the projected decline in production of crude oil from known reservoirs must be countered by the discovery of many new giant oil fields and the expansion of enhanced recovery operations.

duced is just sufficient to offset the operating costs, capital charges, overhead, royalties, insurance, and taxes incurred by the business operation. This limit is reached when anywhere from a few percent to, on the average, 25% of the original oil in place has been recovered, the actual percentage depending on numerous reservoir and fluid parameters. The primary production phase of a solution gas–driven reservoir ends at this point.

The economic life of an oil field can be extended by an increase in the value of crude oil relative to the sum of all the costs involved in producing it. Thus, the primary effect of an increase in the price of crude oil is to extend the life of the reservoir at very low production rates. However, continued production at low and still decreasing rates will yield only a relatively small amount of additional oil.

Obviously, an important factor limiting recovery is the rate at which oil flows from the reservoir. The flow rate, q, is basically a function of the pressure gradient within the reservoir, dP/dr; the viscosity of the oil, μ; the thickness of the reservoir, h; and the relative permeability of the reservoir rock to oil, k_r; and is given by the differential form of Darcy's equation for radial flow

$$q = \frac{2\pi rh.k.k_r.dP/dr}{\mu}$$

where r is the distance between the bore and the point in the reservoir where the flow is measured, and k is the absolute permeability of the reservoir.

The flow rate can be increased either by increasing the pressure gradient, as in waterflooding, or particularly in viscous oil reservoirs, by heating the oil and thereby reducing the viscosity. While waterflooding is beneficial in maintaining the pressure, it also results in undisplaced oil being immobilized and trapped by capillary forces, thereby reducing its relative permeability to virtually zero. The relative permeability, and hence the rate of flow, can be increased by injecting either a surfactant, to reduce the interfacial tension between oil and water (micellar-polymer flooding), or a solute, to swell and reconnect the isolated oil masses (carbon dioxide flooding).

Thermal recovery

Reservoir fluids flow through the porous rock into one or more wells drilled into the reservoir. The pattern of flow as the well is approached is radial, and the fluid is crowded into an ever-decreasing cross section. As a result, most of the pressure drop or energy dissipation occurs very close to the producing well. Darcy's law, rewritten as

$$\frac{dP/dr}{q} = f(1/r)$$

or

$$\frac{dP}{q} = f\left(ln\,\frac{r}{r_w}\right)$$

shows that the pressure drop per unit rate of flow is a logarithmic function of the ratio of the radius of the reservoir, r, to that of the well, r_w. One can readily conceive of drilling a larger bore hole to achieve an increased rate of flow under the pressure available within the reservoir, but the drilling of large holes all the way from the surface is exceedingly expensive.

In practice, a large hole is effectively created by hydraulic fracturing of the reservoir. The well is filled with a fluid, and the pressure is raised to a value comparable to, or greater than, that exerted by the overlying rocks on the reservoir rock (overburden pressure), causing the reservoir to fracture. A viscous gravel-laden fluid is then pumped into the fractures in order to keep them open after the pressure is released. However, the gain in production using this technique is limited to a factor somewhat less than one order of magnitude. Hence, for a viscous oil reservoir that can produce only one or two barrels a day, the absolute gain in productivity is usually insufficient to justify the cost of fracturing.

Because the viscosity of oil falls exponentially as the temperature rises, a more rewarding approach is to reduce the viscosity of the crude oil by heating the reservoir. In the past, many operators have attempted to heat reservoirs by inserting electric heaters down shallow wells or by circulating heated fluids through closed loops down to the bottoms of such wells. Both systems have failed. Inserting heaters down wells does not work satisfactorily because the conductivity of the reservoir rock is very poor, so only the region close to the well is heated. Furthermore, because convective flow is *toward* the well and not away from it into the reservoir, heat is returned to the well and is expelled with the heated oil. When hot fluids are circulated in closed loops, the returning fluids reach the surface at almost the same temperatures at which they are injected, because heat is transferred from the descending hot fluids to the ascending fluids in the parallel or concentric pipes. Much to the chagrin of the operator, fluids reaching the bottom of the well are quite cool owing to heat loss both through the casing to the earth and as a result of heat transfer to the ascending fluid.

The first truly effective enhanced oil recovery technique for viscous crude oils, steam soaking, was discovered quite by accident in Venezuela. In the late fifties in the Mene Grande field, experiments were being conducted into the injection of steam down central wells into heavy-oil reservoirs, with the hope of driving the heated oil into nearby production wells. The steam-injection well blew out. The operators hastily set about repairing the well and resuming steam injection, but the well blew out again. (Blowouts occurred because of the presence of a nearby fault—the same type of fault as that through which the oil had oozed to the surface initially, giving evidence of the reservoirs below.) This second time, the flow of steam escaping from the injection well was followed by a flow of hot, low-viscosity oil that persisted for some time. An idea had been born.

A year later, the operator of the Venezuela field was steam-soaking wells in California: injecting steam for a few days, a week, or even a month, and then allowing the heated oil to flow back through the same well. The steam-soak method, also known as huff-and-puff steaming, or cyclic steam stimulation, spread throughout California. By 1965 almost 20% of California's production was from wells stimulated by steam injection, and California was once again able to produce more than a million barrels of crude oil in a year.

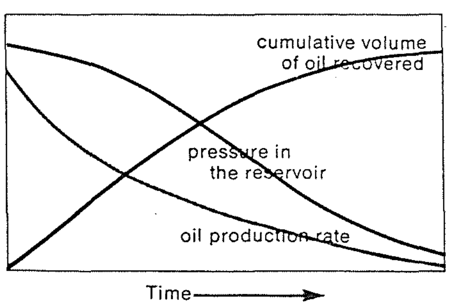


Figure 3. When fluid oil is first removed from a reservoir, the pressure differential is maintained by release of gas from solution. But as more fluid is withdrawn, the pressure drops, and the rate at which oil is produced declines. Therefore, although the reservoir never stops producing oil, at least in theory, it does so more and more slowly, and operations must cease when the value of the oil produced no longer offsets the operating costs.

The steam soak is economically efficient only when the reservoir contains more than 1,000 barrels of oil per acre-foot and is 50 or more feet thick, so that gravity drainage (the free fall of oil through the porous media) can occur. (Units in this paper are those used in the petroleum industry in the U.S.: metric units for viscosity and interfacial tension, British units for everything else.) For gravity drainage to be effective, the vertical permeability—which is usually much lower than the horizontal permeability because of the way in which the nonspherical sand grains are packed in the reservoir rocks—must be good, and in addition the sand layers must be relatively free of shale layers that interrupt vertical drainage. There are not many oil reservoirs in the U.S. that satisfy these criteria, and the steam soak is limited in its major utility to several large fields—Kern River, Midway Sunset, Belridge, San Ardo, and Yorba Linda—in the San Joaquin, Coastal, and Los Angeles basins. Because the steam-soak method was introduced twenty years ago, it is now considered conventional practice, and most of the oil recoverable by this technique has already been included in the estimated ultimate recovery of crude oil.

In most instances, the steam-soak method is being replaced by a steam-drive method that has proved to be extremely efficient in terms of oil recovery, in some cases increasing recovery to as much as 70% of the original oil in place. In a steam-drive operation, steam is injected into alternate wells in order to heat the oil and drive it to adjacent offsetting wells. The success of the method is a direct function of the quantity of latent heat injected, which puts a premium on the quality of the steam that reaches the reservoir. Unfortunately, the water available to most operators tends to be brackish at best, and even after it has been softened, it is impossible to generate steam of more than 80% quality (viz. weight fraction of vapor) without serious problems due to scale deposition in the steam generators. In order to conserve steam quality, the tubing strings that lead the steam down the well are frequently insulated.

Recent development work has been devoted to the fabrication of down-hole steam generators that would avoid the heat loss and resultant loss in quality between the surface generator and the sand face. One advantage of down-hole generators is that pollutants—sulfur and nitrogen oxides—that must now be removed from the stack gases by scrubbers, would be injected into the formation, where they might be efficiently captured by sorption and chemical reaction with the constituent minerals. Nevertheless, the reliability of down-hole generators is still to be demonstrated.

The steam drive works somewhat differently than might be expected from its name. Instead of pushing, or driving, the oil ahead of it, the steam flows over the oil, transferring heat by conduction to the column of oil beneath it. The oil at the interface between the steam and the oil column, its viscosity reduced, is then dragged along by the steam to the producing well. As the oil is depleted, the steam zone expands vertically and still maintains a steam-oil interface. In the steam-drive system, the steam is thus called upon to serve two functions: it both heats and transports the oil. It is difficult to optimize both functions simultaneously, and as a result, some steam must always be circulated through the formation without condensing, in order to provide the driving force to displace the heated oil. Even in some of the most favorable reservoirs, it is necessary to use energy equivalent to burning at least 25% of the crude oil produced, in order to generate the required amount of steam, and in California the current average is about 35%.

The extension of the steam-drive system to very viscous oils—bitumens—that must be heated to still higher temperatures than the lower-viscosity, but still viscous, crudes in California—say, 350°F—for the viscous oils to become sufficiently mobile is limited by the fact that still greater percentages of the oil produced must be consumed for boiler fuel. There is a similar limitation for reservoirs that contain less than 500 barrels per acre-foot, since it requires almost that much fuel to generate enough steam to effectively heat an acre-foot of reservoir sand to the required temperature.

Research is currently underway to increase the efficiency of steam-drive systems. Physically scaled models of the crude oil reservoirs and the steam-drive process, which have been used to study the effect of various fluid and reservoir parameters on the steam drive, are now being used to study the possibility of substituting an inert gas for some of the steam and generating a foam of steam and a noncondensable gas that would be a more efficient displacing fluid. However, one of the best ways to increase the applicability of the steam drive is to substitute coal for crude oil (or residual fuel oil) as the boiler fuel. The cost of a coal-derived Btu of heat energy will probably always be less than that of an oil-derived Btu, and the substitution of coal for oil would release more crude oil for downstream refining and conversion to desirable liquid fuels. The use of coal for generating steam in the oil fields might be the most efficient coal-liquefaction process available to the nation!

In another thermal recovery method, quenched in-situ combustion, what amounts to a steam drive is generated in situ by the simultaneous or alternate injection of air and water into a burning reservoir. Originally in-situ combustion was expected to work simply by propagating a fire front within the reservoir. However, early attempts to employ dry in-situ combustion resulted in numerous operating problems: corrosion of the producing wells, production of very tight emulsions of water in oil that were difficult to treat, and high operating and maintenance costs of the high-pressure, high-volume air compressors that were used to deliver millions of cubic feet of air per day at discharge pressures of about 1,000 psi. Research studies at the Shell Laboratories in Holland revealed that it was possible to inject water and air simultaneously, thereby causing the water to absorb the heat of combustion and be converted to steam without dousing the fire or inhibiting the advance of the combustion wave. The water/air ratio is not very critical to the success of the operation. The chief advantage of this process over direct steam injection is that the steam is generated in situ, and the overall thermal efficiency is therefore much higher. However, many of the operating problems associated with in-situ combustion persist, and use of the technique has not become widespread. Nevertheless, two very successful, low-pressure operations are now underway in northern Louisiana within reservoirs containing crude oil of intermediate viscosity.

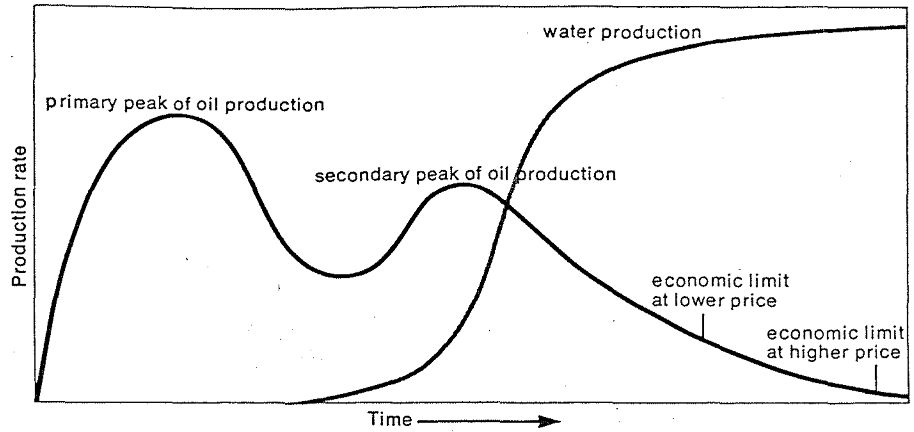
No less than two billion barrels of crude oil will be recovered in the U.S. by steam-drive technology, a scheme conceived initially in a research laboratory and developed subsequently in numerous pilot operations in the field. If continued research and development are successful, it may be possible to recover by this method as much as five billion barrels of oil in the U.S. and a hundred billion or more barrels in Canada and Venezuela, where vast accumulations of bituminous sands are found.

Chemical flooding

During the fifties and sixties, waterflooding was the predominant method for supplementing recovery from solution gas–drive reservoirs. The technology was first developed in Pennsylvania in the 1890s. Corrosion of the casings—pipes cemented into the bore holes to prevent both their collapse and contamination of surface waters by oil—caused by electrochemical cells set up by contact with groundwaters of varying salinity and oxidation potential occurred relatively frequently in the early operations in Pennsylvania. Holes in casings opposing shallow aquifers permitted water to pour into the wells and down into the underlying reservoirs. The encroaching water had the effect of maintaining the pressure in the reservoir and physically displacing some of the crude oil ahead of it. Several operators, correlating a better-than-average oil production with the occurrence of casing problems in offsetting wells, conceived the idea of purposely injecting water into wells alternating with producing wells in order to offset the natural decline in reservoir pressure as oil is removed.

The state of Pennsylvania quickly outlawed this practice, on the basis of erroneous deductions by some geologists, who claimed that contamination of oil sands with water would destroy their productivity. This prohibition gave rise to gangs of moon-

Figure 4. As a result of waterflooding, an oil field shows a secondary peak in production. Shortly thereafter, the fraction of water in the fluids produced increases rapidly. Since it costs as much to lift a barrel of water as a barrel of oil, the net cost per barrel of oil goes up rapidly, and a second economic limit is reached.



light casing-cutters ("a leak is a leak"), who plied their trade throughout the oil fields of Appalachia. They, along with the rum runners, lost their jobs when the prohibition against waterflooding and the Volstead Act were simultaneously repealed.

Waterflooding rapidly became an art in the oil fields of Pennsylvania but did not begin to spread to the rest of the country until the late thirties, when the pace of new oil discovery slackened. The interest in waterflooding was further stimulated by the observation that in many of the giant reservoirs discovered in east Texas in the thirties, production was very prolific because there was no decline in pressure, due to natural influxes of water from adjacent aquifers. The recovery efficiency from the east Texas reservoirs, which contain uniform, clay-free sands, may exceed 70%. Unfortunately, the only other place where such reservoirs occur to any extent is south Louisiana.

Overall, waterflooding is raising recovery efficiency by a factor of about 1.5 to 2 over that produced by solution gas drive alone, to an average of about 40% of the original oil in place in the U.S. Not all reservoirs can be waterflooded, however, due to problems such as heterogeneous sand development or diverse ownership of the mineral rights to a reservoir. The production history of a reservoir subject to waterflooding is shown in Figure 4. The secondary development peak occurs relatively soon after the onset of waterflooding, and shortly thereafter, the production of water increases rapidly, at the expense of the oil production. Waterflooding entails many additional costs: the costs of treating the water for injection into the fine pores (50–100 microns, say) of the reservoir; the cost of fighting brine-borne sulfate-reducing bacteria—*Desulphovibrio desulphuricans,* which is an extremely resistant strain—that lead to sulfide corrosion and the accumulation of organic masses on the reservoir sand face, which reduce its permeability to water; and the sheer cost of power for injecting and then lifting as much as ten volumes of brine for every volume of oil produced. The oil industry in the U.S. today produces about 6 to 7 barrels of water for every barrel of oil.

There are two principal reasons why a waterflood fails to recover more of the oil: the pores within the reservoir rock are not uniform in size (Fig. 5), and the water is usually less viscous than the oil. What happens is that the fluids move faster through the larger pores (Fig. 6), and once a water-oil interface gets ahead of the average position, the flow of water is accelerated relative to that of oil because of its lower viscosity. Hence, in most reservoirs, the water eventually tends to flow as a finger through the oil and bypass some of it. This effect is less pronounced than might be anticipated on the basis of the heterogeneity of the pores, owing to the fact that it is water, not oil, that preferentially wets the minerals comprising the reservoir. As a result, water is taken up by the fine pores of the reservoir rock. As the oil is forced through a constriction into a pore already filled with water, the changing curvature of the oil glob affects the distribution of capillary pressure on its surface in such a way that the water streams to the constriction and cuts off the oil thread, leaving it surrounded by water. Once the leading edge of the oil glob has been snapped off, the pressure required to deform it so that it can squeeze through the constriction is so great as to be unattainable without rupturing the reservoir itself.

The injection of surfactants in aqueous solution to affect interfacial tension and reduce capillary pressure to a level that would permit release of immobilized oil was proposed many years ago. To lower the capillary pressure by this amount would require lowering the interfacial tension between oil and water to about 10^{-3} to 10^{-4} dyne/cm—several orders of magnitude less than the normal values of about 20 to 30 dynes/cm. Such a reduction can indeed be achieved in vitro, but in crude oil reservoirs the effectiveness of simple surfactants is vitiated by adsorption of the surfactant onto reservoir minerals, salting-out by reservoir brines, and bacterial degradation. Even more important, a low interfacial tension prevents the fine pores from taking up water and permits the surfactant solution to finger from the injection well to the production well quite rapidly. Very sophisticated solutions of surfactants, co-surfactants, and inorganic salts have been developed that overcome many of these problems. The solutions are frequently loaded with water-soluble polymers, hydrolyzed acrylate polymers, and polysaccharides, to prevent fingering and to improve the sweep of the reservoir by the injected solution. They are known as micellar-polymer fluids, because the surfactant is usually present at concentrations above the critical concentration for micelle formation; unfortunately they are very expen-

Figure 5. The chief factors limiting recovery efficiency are the heterogeneity in grain and pore sizes, shown in this scanning electron micrograph of a reservoir sand (enlarged ~75 times), and the viscosity of the crude oil, which is greater than that of water.

sive. Although extremely encouraging results have been obtained with numerous formulations in many laboratories, pilot studies in the field have so far been generally discouraging.

One of the great problems in developing effective chemical floods for use in real reservoirs is our inability to scale the process physically in the laboratory. The laboratory experiments are done on sand packs and stacked cores 5–7 cm in diameter that have been taken from the reservoir, and the experiments are over in hours or days; in the reservoir, however, dimensions are measured in hundreds of meters and time scales in years. The problem stems from the impossibility of simultaneously scaling adsorption and capillarity on the one hand and viscous fluid flow on the other. It is conservatively estimated that 250–500 million dollars has already been spent on research and development studies of chemical flooding. Reviewers of the technology on behalf of the U.S. Department of Energy and the Office of Technological Assessment of the U.S. Congress have concluded that there is not much prospect for a significant contribution to enhanced oil recovery from chemical flooding in the coming decades. The process seems to require more sophisticated control than can be achieved in the oil field, where, once the fluids are injected, the reservoir itself takes over. However, the promise of the method is so great that research is continuing despite the disappointments.

Carbon dioxide flooding

At the time of the Suez crisis in the late fifties, the oil industry, faced with the curtailment of supplies to western Europe (the U.S. was not a significant importer at the time), engaged in a sizable amount of research and development work in solvent, or miscible, flooding. The preferred solvent was LPG (liquefied petroleum gas, primarily propane), which was then in little demand and was relatively inexpensive. The theory behind the idea is quite straightforward. A slug of LPG—about 5% of the size of the reservoir, say—is injected into the reservoir, as a result of which the residual crude oil, which is miscible with LPG, is banked up ahead of it. The LPG is followed by natural gas, which, since the two are miscible, displaces it, and water, which, because of its higher viscosity, displaces the natural gas in a pistonlike fashion. Field tests gave rather disappointing results, however. The principal problem was traced to the fingering of LPG through any oil bank that developed, owing to its much lower viscosity. In other words, fingering due to an unfavorable viscosity ratio and reservoir heterogeneity occurs in both miscible and nonmiscible displacement. The ending of the Suez crisis

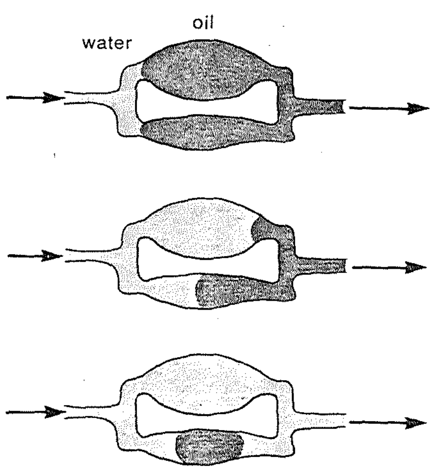


Figure 6. Water injected into the reservoir will advance faster in some interstices than others, because of the heterogeneity of the porous network. The oil in the bypassed channels becomes trapped by capillary forces. This schematic representation of water invasion in parallel pores originally filled with oil shows (*top to bottom*) the water as it first enters the pore, the oil/water boundary moving faster in the upper channel, and the snap-off and retraction of the oil thread in the lower pore. Once isolated, the pressure required to release the oil is unattainable in practice.

and the gradual increase in the value of LPG as a feedstock for the petrochemical industry terminated further work on this process.

Owing to the more sustained oil-supply problems of recent years, attention has again turned to the potential of so-called miscible flooding. It was discovered that carbon dioxide at high pressures has a significant solubility in most crude oils, although there is a miscibility gap at mol fractions above 60%, even at pressures as high as 5,000 psi. Field pilot studies have demonstrated conclusively that carbon dioxide at high pressures will mobilize and displace oil trapped by waterflooding. However, the amount of carbon dioxide required to recover an additional barrel of crude oil was found to be quite high—as much as 30,000 standard cubic feet, compared to a theoretical value on the order of 2,000. Such a high consumption of carbon dioxide negates the economic feasibility of the process.

The actual mechanism by which the carbon dioxide recovers crude oil is the subject of much discussion in the technical literature, but precise comprehension could lead to breakthroughs in the optimization of carbon dioxide use. Some investigators believe that carbon dioxide functions by extracting some of the lighter components of the crude oil, thereby forming a new phase that can miscibly bank up and displace the residual crude. Others believe that the carbon dioxide condenses in the residual oil to form such a new, miscible phase. Considering the experience with LPG flooding, it seems unlikely that a relatively small volume of a miscible fluid can maintain its integrity and stabilize the displacement process.

Studies based on scaled physical models have provided further insight into the mechanism of carbon dioxide displacement. In most applications, carbon dioxide is in dense gaseous form, since the critical temperature is only 88°F. At supercritical pressures, carbon dioxide may have a density that exceeds that of the crude oil and approaches that of water. The viscosity of the dense gas is usually less than 0.1 centipoise—much less than that of water—and when injected into a waterflooded reservoir, this low-viscosity carbon dioxide tends to finger through the more viscous aqueous phase that saturates most of the reservoir volume. It is only after carbon dioxide has displaced a significant amount of water that it can reach the residual oil that has been occluded and immobilized by the water. Upon contact, it dissolves in and swells the oil globs. Erstwhile immobilized globs begin to touch each other, and the relative permeability to the oil phase again becomes large enough for oil to flow.

It can be seen that this process is basically inefficient, because the carbon dioxide has to displace the water before displacing the residual crude oil. As a result, the quantity of carbon dioxide theoretically required for mere volumetric replacement of the crude oil—about 2,000 standard cubic feet per barrel—cannot be achieved. The work to date suggests that 7,000–10,000 standard cubic feet per barrel may be the best that can be done. This is accomplished by injecting carbon dioxide in discontinuous slugs, rather than as a continuous stream. Although this lowers the amount of carbon dioxide that is required, it also reduces the percentage recovery of the residual crude oil.

The minimum cost of carbon dioxide consists of the costs of compression and prevention of corrosion—on the order of \$0.50 to \$1.00 per thousand standard cubic feet—plus the cost of procuring it. There are some natural, subsurface accumulations of carbon dioxide in the U.S., notably under the Jackson Dome in Mississippi and in several structures in the Rocky Mountains. Carbon dioxide from such sources would have to be piped to the oil fields, and the ultimate cost is estimated to be in the range of \$1 to \$2 per thousand cubic feet. Another potential source of carbon dioxide is in the stack gases of power plants and other industrial installations that burn fossil fuels; the gases would have to be purified to reduce—or virtually eliminate—the nitrogen content, since nitrogen is not as soluble in crude oil as carbon dioxide at comparable pressures. The cost of purification has been estimated to be on the order of \$1 to \$2 per thousand cubic feet. If adequate supplies of carbon dioxide can be made available, billions of additional barrels of crude oil may be recovered in the U.S. by this process; however, it is important to note that the use of carbon dioxide will add \$15–50 to the cost of each barrel of oil.

Research and development have already led to the implementation of the steam-drive process for the extensive recovery of viscous crude oils from reservoirs with a high saturation of petroleum. The additional production that results—over 300,000 barrels per day at the present time—may be increased to as much as 500,000 barrels per day by 1990 if developments in progress, including the substitution of coal as fuel for the steam generators, come to fruition. Although work with carbon dioxide has been transferred successfully from the research laboratory to demonstrations in the field, more optimization is required to ensure a marginal economic return. Currently available solutions for micellar-polymer flooding may be limited to use in shallow reservoirs, where many wells can be drilled per unit area and fluid velocities are consequently high, thereby compensating for the current failure to achieve ultralow interfacial tensions.

In view of the stark decline in producing capacity in the U.S. and the low probability of finding a significant number of giant and supergiant fields in the future, the enhanced oil recovery technology developed to date can, at very best, be counted on only to slow down the decline in domestic crude oil supplies. Because of the national need, continuing efforts are certainly called for, but they should not be substituted for the development of alternate energy sources.

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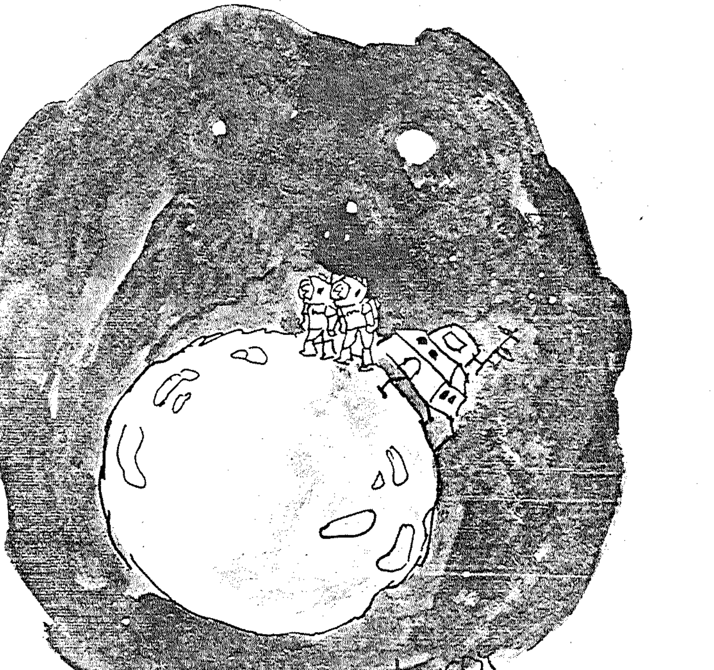

"Another one inhabited. That's three down and several hundred billion to go."