Has the Time Come for EOR?

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For twenty years, much of the E&P industry turned away from the term enhanced oil recovery. Yet, during that period, field successes through flooding with steam and carbon dioxide continued. Decreasing production levels in maturing fields have revived interest in enhanced recovery techniques in many parts of the world. Improved technologies for understanding and accessing reservoirs have increased the possibilities for successful EOR implementation.

A tantalizingly large source of additional oil sits within reach of existing oilfield infrastructure. Operating companies know where it is, and they have a good idea how much is there. This resource is oil left in reservoirs after traditional recovery methods, such as primary production and waterflooding, have reached their economic limits.

The percentage of original oil remaining varies from field to field, but a study of 10 US oil-producing regions found that about two-thirds of the original oil in place (OOIP) remained after traditional recovery methods were exhausted.[1] The study found that about 23% of the oil remaining in those regions could be produced using established CO_2 flood technologies. That technically recoverable resource of almost 14 billion m^3 [89 billion bbl] of oil could, by itself, supply more than a decade of US consumption at current rates. Interest in methods to recover those resources has increased in recent years.[2]

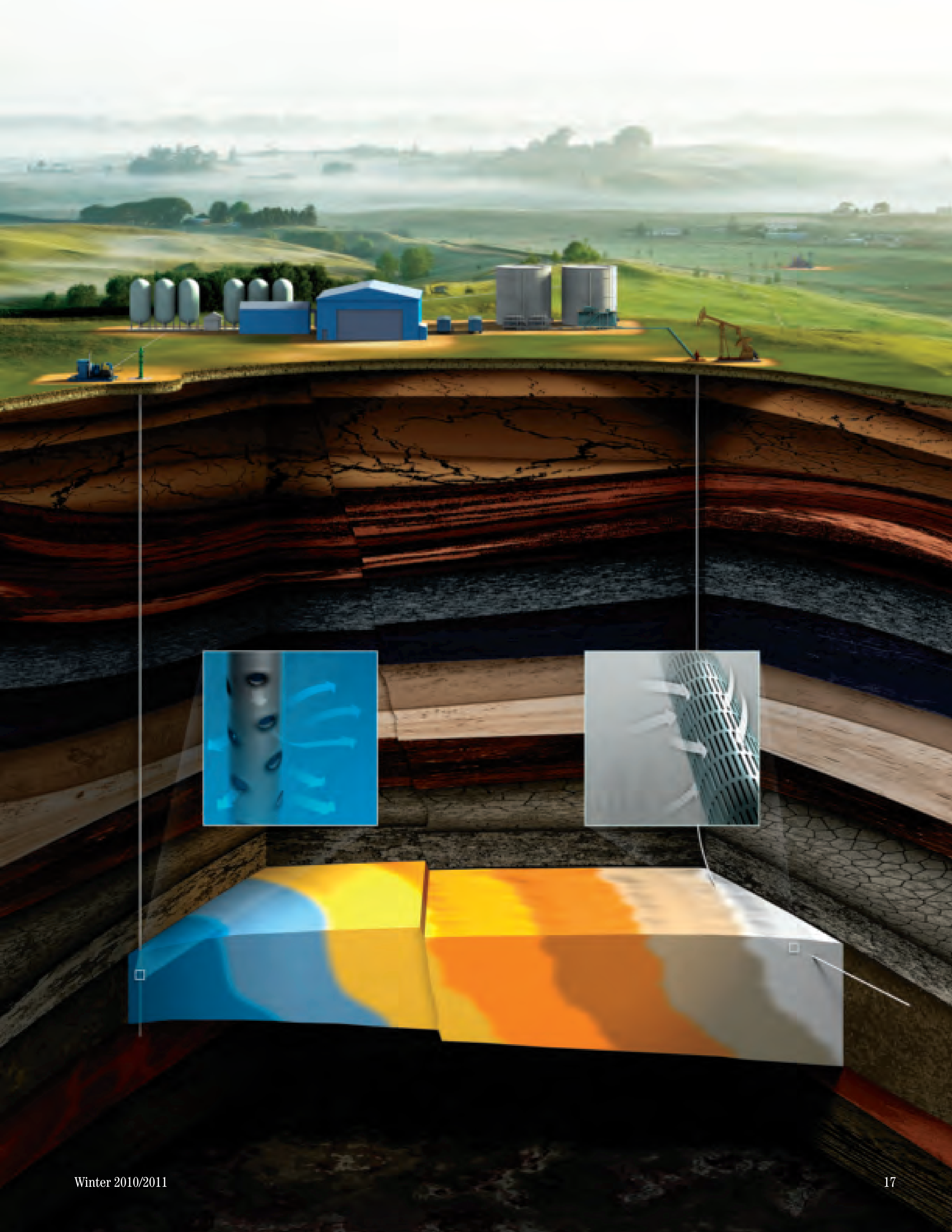
Worldwide, the number of mature fields will continue to grow, with more passing their production peak each year. Operators work to optimize recovery from these fields, and in the past 20 years tremendous advances have been made that help access the remaining resource. Bypassed oil can be located with advanced logging tools, 4D seismic evaluations, crosswell imaging technologies, 3D geomodeling and other state-of-the-art software systems. The industry has made strides in understanding clastic sedimentary structures and carbonate petrophysics to construct models and in reservoir geomechanics to plan well paths. Today, the industry can drill more-complex wells and precisely reach multiple targets containing untapped oil. Completions can be designed to better monitor and control production and injection downhole and to measure fluid properties both in situ and at the surface. Tailored chemicals can be designed to improve recovery, and advanced research is looking at the use of nanoparticles to mobilize remaining oil. In addition, the world is now more environmentally aware, presenting the opportunity to use depleted reservoirs for storage of CO_2 while also increasing recovery factors.

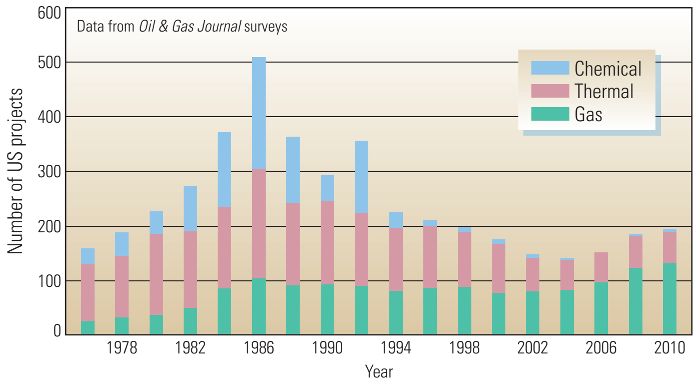
Methods for recovering oil are referred to by several terms.[3] An early concept described sequential phases of production using the terms primary (pressure depletion, including natural water or gas drive), secondary (mostly

1. Hartstein A, Kusskraa V and Godec M: "Recovering 'Stranded Oil' Can Substantially Add to U.S. Oil Supplies," Project Fact Sheet, US Department of Energy Office of Fossil Energy (2006), http://fossil.energy.gov/programs/oilgas/publications/eor_co2/C_-_10_Basin_Studies_Fact_Sheet.pdf (accessed November 8, 2010).
2. For a recent review of enhanced recovery methods: Manrique E, Thomas C, Ravikiran R, Izadi M, Lantz M, Romero J and Alvarado V: "EOR: Current Status and Opportunities," paper SPE 130113, presented at the SPE Improved Oil Recovery Symposium, Tulsa, April 24–28, 2010.

   For results of a biennial survey of activity: Moritis G: "Special Report: EOR/Heavy Oil Survey: CO_2 Miscible, Steam Dominate Enhanced Oil Recovery Processes," *Oil & Gas Journal* 108, no. 14 (April 19, 2010): 36–53.

   Moritis G: "EOR Oil Production Up Slightly," *Oil & Gas Journal* 96, no. 16 (April 1998): 49–77, http://www.ogj.com/index/current-issue/oil-gas-journal/volume-96/issue-16.html (accessed February 7, 2011).
3. A proposal made to the SPE in 2003 to clarify the definitions was not implemented. See Hite JR, Stosur G, Carnahan NF and Miller K: "IOR and EOR: Effective Communication Requires a Definition of Terms," *Journal of Petroleum Technology* 55, no. 6 (June 2003): 16.





^ EOR project history. The number of ongoing EOR field projects in the US peaked in 1986, then declined for nearly 20 years. Since 2004, the number of projects has been rising again. Currently, miscible gas EOR projects (green) dominate, followed by thermal projects (pink). At present, only a few chemical floods (blue) are underway. [Data from Moritis (1998 and 2010), reference 2.]

water- or gasflooding, including pressure maintenance) and tertiary (everything else). However, with advances in reservoir modeling, engineers sometimes found that waterflooding should occur before pressure decline, or that a tertiary method should be used in place of a waterflood, or that potential recovery by a tertiary method might be lost due to reservoir damage from earlier activities. The terms lost their original sense of a chronological order. Engineers today often include methods formerly termed tertiary as part of the field development plan from the beginning.

Another distinction that has been difficult to define is that between improved oil recovery (IOR)—which had essentially the same definition as secondary recovery—and enhanced oil recovery (EOR), which included more-exotic recovery methods. Over the years, a few EOR processes were commercially successful in many applications, and some companies began referring to them as a form of IOR instead. This relabeling process accelerated after many companies severely cut or stopped funding EOR research during the era of low crude-oil prices in the 1980s and 1990s.[4]

Regardless of the labels used, the range of activities applied to increase recovery from reservoirs is wide. Waterflooding is common as an economical way to displace oil and provide pressure support. Methods that improve physical access to oil include infill drilling, horizontal drilling, hydraulic fracturing and installation of certain types of completion hardware. Conformance control improves recovery by blocking off high-permeability zones either by mechanical means, such as inflow control devices, or by injecting fluids, such as foam or polymer, that plug those zones; these activities improve recovery from lower-permeability zones. Thermal processes are common to decrease viscosity of heavy oils and to mobilize light oils.

Finally, injecting chemicals and effective recovery gases—such as CO_2—can change certain physical properties of the crude oil-brine-rock (COBR) system. These methods alter interfacial tension (IFT), mobility, viscosity or wettability, swell the oil or alter its phase composition.

The specific method or combination of EOR methods applied to recover oil is typically based on an engineering study of each reservoir. In most cases, the objective is to achieve the most economical return on investment, but some national oil companies have different goals, such as maximizing ultimate recovery. Operators examine several risk factors, including oil price, need for a long-term program to achieve satisfactory return on investment, large upfront capital investments and cost of drilling additional wells and running pilots.

Many oil-recovery techniques depend on pore-level interactions involving COBR-system properties. Most projects begin by screening EOR candidates against field parameters such as temperature, pressure, salinity and oil composition.[5] Many companies have established screening criteria for EOR projects, but since these are changing as new technologies are introduced, this article does not present a specific set of criteria.[6]

EOR techniques that pass initial screening are further evaluated based on laboratory studies of the rock and fluids and on simulation studies that use field properties. If laboratory tests have positive results, the operator might next perform field-level tests, ranging from single-well to multiple-pattern pilots. If the early steps indicate likelihood of a positive economic result, full-field implementation can follow.

EOR technology has even resurrected significant levels of production after abandonment. The Pru Fee property in Midway-Sunset field, San Joaquin basin, California, USA, produced about 2.4 million bbl [380,000 m^3] of heavy oil between start of production in the early 1900s and abandonment in 1986.[7] Cyclic steam injection had been partially successful in increasing production, but by the time of abandonment, the oil rate was less than 10 bbl/d [1.6 m^3/d] for the entire field.

In 1995, The US Department of Energy (DOE) selected the Pru Fee property for a demonstration EOR project. After cyclic steamflooding in several old wells at the center of the site demonstrated good production levels, the project team added 11 new producers, 4 injectors and 3 temperature-observation wells, obtaining production rates in the range of 363 to 381 bbl/d/well [57.7 to 60.6 m^3/d/well]. In 1999, operator Aera Energy added 10 steamflood patterns.[8] By 2009, the site had produced an additional 4.3 million bbl [684,000 m^3] of oil after original abandonment.[9]

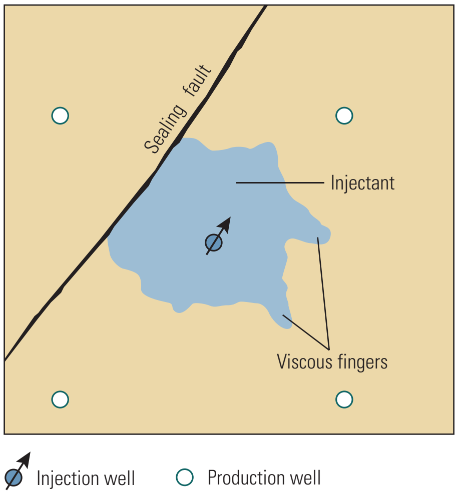
This article describes a broad range of recovery methods, but focuses on techniques traditionally considered EOR—and referred to as such—including miscible and immiscible gasflooding, chemical flooding and thermal technologies. A case study for a Gulf of Mexico field evaluated its gasflooding potential. An extensive laboratory evaluation indicates how to tailor a chemical combination for EOR injection. Another case, from Oman, describes the first use of a method for performing rapid single-well, in situ evaluations of injection to demonstrate the efficiency of a flooding process.

Displacement Efficiency

Waterflooding in oil fields was first legalized in the US in the state of New York in 1919, but so-called unintentional waterflooding was recorded as early as 1865, near Pithole City, Pennsylvania, USA.[10] Less than a decade after waterflooding became legal, inventors proposed means to improve flood recovery by adding surfactant to lower interfacial tension or by injecting alkali to generate surfactant in situ—both now accepted EOR methods.[11]

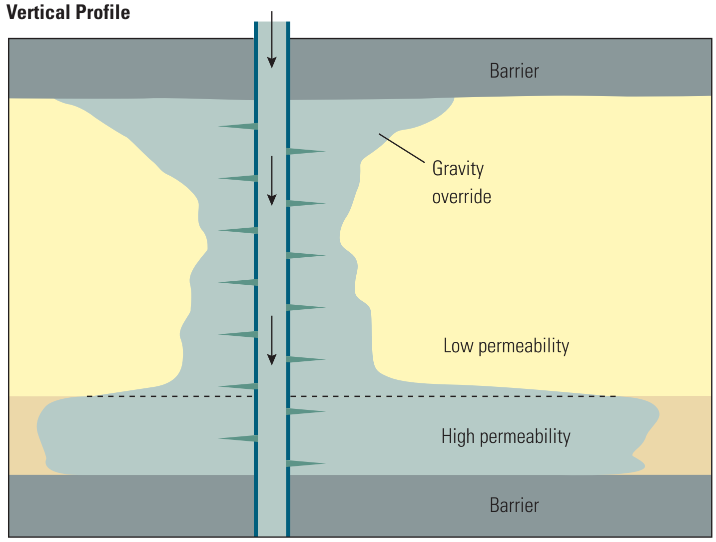
A boom of activity in EOR techniques came after the oil-price rise of the 1970s, but the bust in the late 1980s led many companies to abandon marginal and uneconomic projects (above left). A sustained period of higher crude-oil prices in

Pattern Flood



^ Areal displacement efficiency. Oil can be bypassed because of inefficiencies in macroscopic sweep. A pattern flood can be affected by a heterogeneous formation (such as the presence of sealing faults) or by fingering of a less viscous injectant into the oil.

Vertical Profile



^ Vertical displacement efficiency. Vertical sweep can be affected by viscous fingering, as well as by preferential movement of fluids along a high-permeability thief zone or by gravity override of injection gas (as indicated here) or underride of injection water.

the past 10 years has revived operator interest in some of these techniques and encouraged introduction of new ones. That interest has survived the more recent price volatility.

Many techniques aimed at improving recovery are designed to increase the efficiency of oil displacement using injected water or other fluids. Some methods address the *macroscopic* displacement efficiency, also called sweep efficiency. Other recovery methods focus on *microscopic*, or pore-scale, displacement efficiency. The overall displacement efficiency is the product of both macroscopic and microscopic efficiencies.

Macroscopic displacement—At the scale of interwell distances, oil is bypassed because of lateral or vertical formation heterogeneity, well-pattern inefficiencies or low-viscosity injection fluids. Improving sweep efficiency is typically one of the goals of reservoir engineering and modeling. Although the efficiency of well patterns such as five- or nine-spots can be determined for a uniform reservoir, reservoir heterogeneities affect flow paths (above left). If these are unknown or not compensated for by adjusting the pattern, then sweep efficiency suffers.

Advances in seismic acquisition, processing and interpretation have given reservoir engineers new tools to locate faults and layer changes. Some companies have applied 4D seismic methods to follow a flood front through a reservoir, allowing their engineers to update models based on observed flow geometries. Pattern sweep efficiency can be improved by infill drilling or the use of horizontal or extended-reach wells and by creating zones within well intervals using downhole flow-control devices.[12]

Sweep is also affected by vertical variations in properties (above right). In particular, a high-permeability, or thief, zone will be swept by a waterflood before adjacent low-permeability zones are swept. Techniques can be applied to equalize the flow in the zones, most commonly by decreasing thief-zone permeabilities. If there is little or no communication between zones, the thief zone can be shut off near the injection site, but if the zones communicate throughout the reservoir, it may be necessary to design an injectant that will block the zone all the way to the producing well. For both near-well and far-field solutions, engineers use foams and polymers for this purpose.

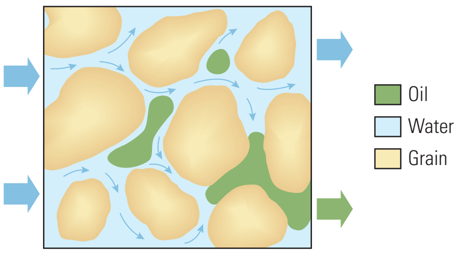
Viscous fingering is another concern of macroscopic displacement efficiency. If the displacing fluid—typically water—is significantly less viscous than the oil it is displacing, the flood front can become unstable. Rather than being linear or radially symmetric, the leading edge of the front

4. One indication of the rise and fall of the term EOR is the naming of the biennial meeting sponsored by the SPE in Tulsa. The first five meetings, spanning 1969 through 1978, were called the SPE Improved Oil Recovery Symposia. From 1980 through 1992, the US Department of Energy jointly sponsored the conferences, and they were called the SPE/DOE Enhanced Oil Recovery Symposia. In 1994, the conferences returned to sole sponsorship by SPE, and again became the SPE Improved Oil Recovery Symposia, which they remain today. Throughout this 31-year period, conference papers covered topics typically considered both IOR and EOR.
5. Lake LW, Schmidt RL and Venuto PB: "A Niche for Enhanced Oil Recovery in the 1990s," *Oilfield Review* 4, no. 1 (January 1992): 55–61.
6. For an overview of EOR engineering, including criteria to consider: Green DW and Willhite GP: *Enhanced Oil Recovery*. Richardson, Texas, USA: Society of Petroleum Engineers, SPE Textbook Series, vol. 6, 1998.

   For another set of criteria: Taber JJ, Martin FD and Seright RS: "EOR Screening Criteria Revisited—Part 1: Introduction to Screening Criteria and Enhanced Recovery Field Projects," *SPE Reservoir Engineering* 12, no. 3 (August 1997): 189–198.

   Taber JJ, Martin FD and Seright RS: "EOR Screening Criteria Revisited—Part 2: Applications and Impact of Oil Prices," *SPE Reservoir Engineering* 12, no. 3 (August 1997): 199–205.
7. Schamel S: "Reactivation of the Idle Pru Lease of Midway-Sunset Field, San Joaquin Basin, CA," *The Class Act: DOE's Reservoir Class Program Newsletter* 7, no. 2 (Summer 2001): 1–6, www.netl.doe.gov/technologies/oil-gas/publications/newsletters/ca/casum2001.pdf (accessed November 10, 2010).
8. Schamel S and Deo M: "Role of Small-Scale Variations in Water Saturation in Optimization of Steamflood Heavy-Oil Recovery in the Midway-Sunset Field, California," *SPE Reservoir Evaluation & Engineering* 9, no. 2 (April 2006): 106–113.
9. State of California Department of Conservation Division of Oil, Gas and Geothermal Resources, Online Production and Injection database, http://opi.consrv.ca.gov/opi (accessed December 3, 2010).
10. Blomberg JR: "History and Potential Future of Improved Oil Recovery in the Appalachian Basin," paper SPE 51087, presented at the SPE Eastern Regional Meeting, Pittsburgh, Pennsylvania, USA, November 9–11, 1998.
11. Uren LC and Fahmy EH: "Factors Influencing the Recovery of Petroleum from Unconsolidated Sands by Water-Flooding," *Transactions of the AIME* 77 (1927): 318–335.

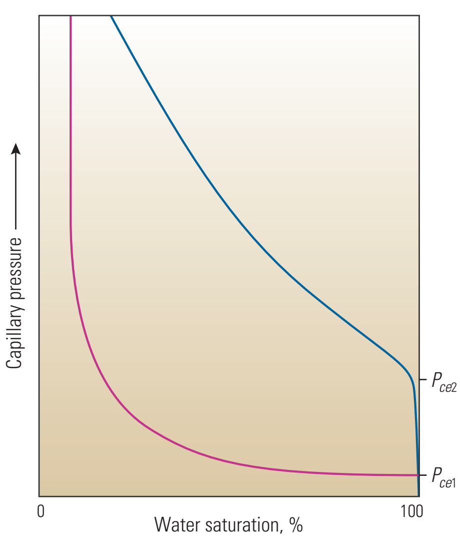
    Atkinson H: "Recovery of Petroleum from Oil Bearing Sands," US Patent No. 1,651,311 (November 29, 1927).
12. Ellis T, Erkal A, Goh G, Jokela T, Kvernstuen S, Leung E, Moen T, Porturas F, Skillingstad T, Vorkinn PB and Raffn AG: "Inflow Control Devices—Raising Profiles," *Oilfield Review* 21, no. 4 (Winter 2009/2010): 30–37.



^ Microscopic displacement. At the microscopic scale, oil can be trapped in the middle of pores (for example, *top right*) when water flows around the oil in a water-wet formation. Oil that is connected to flow paths (*bottom right*) continues to be displaced.

forms waves that transition to fingers extending farther into the oil. Eventually, water fingers reach the producing well. At that point, additional injected water will preferentially follow the water-filled paths. Engineers avoid this by increasing water viscosity through methods such as adding polymer or foam to it.

Microscopic displacement—At the other end of the size scale, small blobs of oil can be trapped within a pore or a connected group of pores (above). Oil at this scale is trapped because viscous or gravity-drive forces within the pore space are insufficient to overcome capillary forces.



^ Capillary pressure curves. Formations have different capillary pressure relationships, depending on the distribution of pore throats in the rock. Starting fully saturated with water, the rock is exposed to oil at increasing capillary pressures, and the capillary pressure curve indicates the degree of saturation at each capillary pressure. A clean, uniform sandstone (pink) with large pore throats will have a low capillary entry pressure P_{ce1} and a rapid decline in water saturation as the capillary pressure increases. In contrast, a poorly sorted sandstone (blue) can have a high capillary entry pressure P_{ce2} and a slow decrease in saturation as the capillary pressure increases.

The amount of oil trapped within pore spaces depends on a variety of physical properties of the COBR system. One of these properties is wettability.[13] In a strongly water-wet rock, water preferentially coats the pore walls. Conversely, strongly oil-wet surfaces within a pore are preferentially contacted by oil. In an intermediate-wetting condition, the pore surfaces do not have a strong preference for either water or oil.

Most reservoir rocks have a mix of wetting conditions: The smaller pores and spaces near grain contacts are generally strongly water wetting, while the surfaces bounding the larger pore bodies may range from less water wetting to oil wetting. Thus, the wettability of the bulk material is between the two extremes. Although measures of wettability, such as Amott-Harvey or US Bureau of Mines (USBM) wettability tests, may result in similar index numbers for intermediate and mixed-wet rocks, the two are distinct wetting conditions. Intermediate wettability applies to rocks with all surfaces of neutral wetting preference, while mixed wetting applies to rocks with surfaces of markedly different wettability.

Optimal recovery from waterflooding is obtained in mixed-wet material that is slightly water wetting.[14] The reason for this can be made clear by a discussion of pore-level oil-trapping mechanisms.

Most reservoirs were water-wet formations before oil accumulated. Oil migrating into a formation must overcome the rock's wetting forces before it can enter the pores. This resistance is the rock's capillary entry pressure, which is the pressure difference between the water and oil phases needed to overcome wetting forces in small openings. The capillary entry pressure is inversely proportional to the radius of the opening, or pore throat, through which the oil must pass.

Since rocks have a variety of pore throat sizes, any given rock will have a distribution of capillary entry pressures. Pores having the largest throats are the first to be invaded by the nonwetting phase, and those with progressively smaller pore throats are invaded at progressively higher pressure differences between the phases. Thus, a rock will have a capillary pressure curve indicating the degree of invasion—represented by the remaining water saturation—at each capillary pressure (left).

In a reservoir, the source of the pressure difference between the phases is their density difference. The depth in the reservoir at which the water- and oil-phase pressures are the same is the free-water level.[15] The product of the height above the free-water level, the acceleration of gravity and the density difference between phases gives the pressure difference for that height. That pressure difference supplies the capillary pressure, resulting in decreasing water saturation with height above the free-water level based on the pore throat distribution in the rock. This is seen in some reservoirs as a transition zone, where the water saturation changes with depth in a rock with uniform properties.[16]

In addition to providing insight into the initial saturation distribution in a reservoir, capillary pressure is also important for flow dynamics. The capillary behavior of a formation influences the irreducible water saturation after waterflooding. Thus, one of the most important quantities to know about a reservoir, the maximum amount of oil that can be recovered by waterflooding, is strongly influenced by the pore-level physics of wetting.

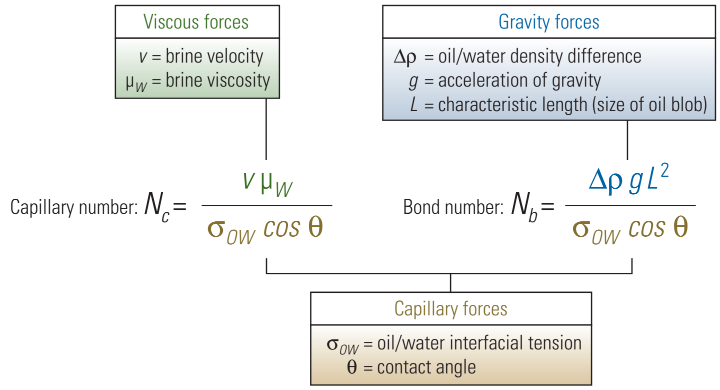
If the oil in a pore contains surface-active components, it can displace a thin layer of water and contact the rock surface. Thus, the oil in pores can alter the wettability of the pore surface, making it less strongly water wetting or even oil wetting. However, the tight spaces in pores, such as near grain-to-grain contacts, retain their water coatings and remain strongly water wetting. This is thought to be the origin of the mixed-wetting character of most reservoirs.[17]

When oil is displaced either through a natural or forced waterdrive, water can encroach into pore spaces in three ways. It can follow existing paths of continuous water in the smallest nooks and crannies of the pore structure and slowly increase the thickness of that water film. However, the relative permeability for water flowing along that path is vanishingly small outside

13. For more on wettability: Abdallah W, Buckley JS, Carnegie A, Edwards J, Herold B, Fordham E, Graue A, Habashy T, Seleznev N, Signer C, Hussain H, Montaron B and Ziauddin M: "Fundamentals of Wettability," *Oilfield Review* 19, no. 2 (Summer 2007): 44–61.
14. Jadhunandan PP and Morrow NR: "Effect of Wettability on Waterflood Recovery for Crude-Oil/Brine/Rock Systems," *SPE Reservoir Engineering* 10, no. 1 (February 1995): 40–46.
15. Free-water level may not correspond to the oil/water contact because of the filling history of the reservoir.
16. A change in distribution of pore throats, such as occurs in a sand-shale sequence, also results in an abrupt saturation change because the rocks have different capillary pressure curves. Filling and depletion history can also influence the saturation distribution.
17. Mixed wettability can also occur because different minerals present in the rock have different affinities for water and oil.
18. Seccombe J, Lager A, Jerauld G, Jhaveri B, Buikema T, Bassler S, Denis J, Webb K, Cockin A and Fueg E and Paskvan F: "Demonstration of Low-Salinity EOR at Interwell Scale, Endicott Field, Alaska," paper SPE 129692, presented at the SPE Improved Oil Recovery Symposium, Tulsa, April 24–28, 2010.

the transition zone because the water layers are so thin. Alternatively, if the formation is strongly water wetting, the rock's affinity for imbibing water will force oil out of the smaller pore spaces first, then from increasingly larger pores as the flood progresses. The flood water connects with the thin layers of water present on the grains. Finally, in an oil-wet or mixed-wet formation of the type described above, water invades the large pores as the nonwetting phase if the water-phase pressure is sufficient to overcome the capillary entry pressure.

In all three cases, as the waterflood progresses, oil can become trapped within pores as water finds easier flow paths around it. Once the water breaks the connection between an oil blob and the oil sweeping out ahead of the waterfront, the blob becomes much more difficult to move (right). This disconnected oil has to move through pore throats that probably were never altered from strongly water wetting (even in a mixed-wet formation), but the only drive force is the pressure difference between the water upstream and that downstream of the blob.



^ Comparison of forces. Capillary forces can trap isolated oil in the pore space. Typically, capillary forces are overcome by either viscous or gravity forces. Two dimensionless numbers are used to compare these forces. The capillary number N_c (*left*) is a ratio of viscous to capillary forces. To mobilize the oil, either the brine velocity must be increased or the oil/water IFT must be brought near zero, which produces a large value of the capillary number. In a system where gravity is more important, such as gravity stabilized flow, the relevant quantity to maximize is the Bond (also called the Eötvös) number N_b (*right*). In most cases, the wettability is taken as strongly water-wet, with a contact angle near zero.

One of the reasons that maximum oil recovery occurs in mixed-wet systems is that oil in contact with the more oil-wetting (or less water-wetting) pore surfaces can remain continuous at lower oil saturations than in a water-wet system. More of the oil can drain from the pores before it becomes trapped by water on all sides.

However, in a strongly oil-wetting formation, remaining oil is trapped in the smaller pores and its relative permeability gets vanishingly small as water fills the larger pores. The waterflood residual oil recovery for a formation that is strongly oil wetting is less than that of a mixed-wetting formation.

Flooding Methodologies

Traditionally, many EOR techniques target the oil remaining after waterflooding. Most methods fall into one of three general categories: gasflooding, chemical flooding and thermal techniques. Each of these has a variety of forms, and they can be combined to achieve specific results (below).

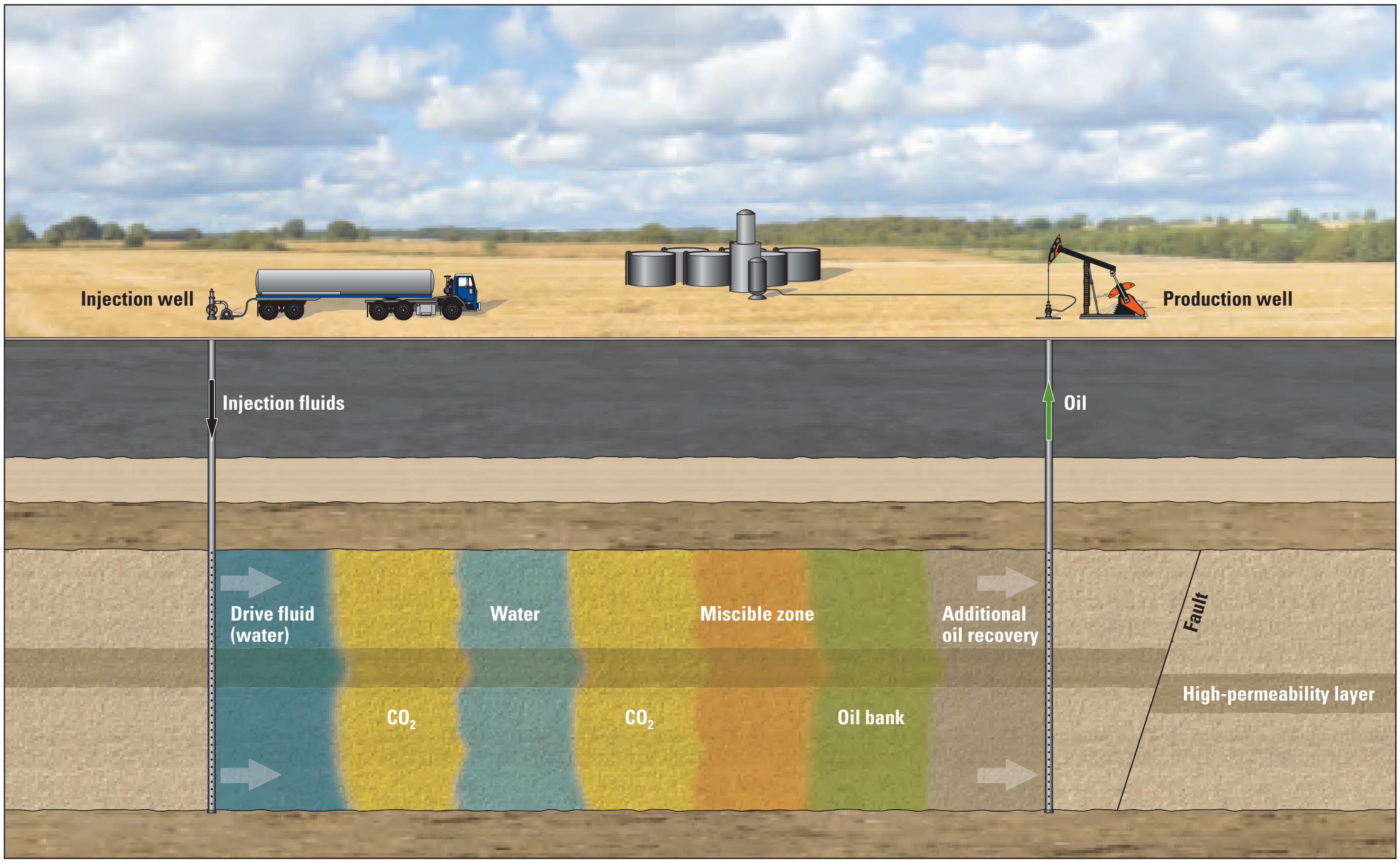
Waterflooding is generally not considered an EOR method unless it is combined with some other flooding method. However, over the past 15 years, the oil industry has investigated low-salinity waterflooding, which, in some situations, does recover additional oil following a typical, high-salinity waterflood.[18] Although the oil-recovery mechanism is not universally accepted,

EOR Method		Pressure Support	Sweep Improvement	IFT Reduction	Wettability Alteration	Viscosity Reduction	Oil Swelling	Hydrocarbon Single Phase	Compositional Change[1]	Incremental Recovery Factor
Waterflood	Waterflood									Base case[2]
	Engineered water									Low
Gasflood: immiscible	Hydrocarbon									Moderate
	CO_2									High
	Nitrogen or flue gas							3	3	Moderate
Gasflood: miscible	Hydrocarbon								4	High
	Hydrocarbon WAG								4	Very high
	CO_2									High
	CO_2 WAG									Highest
Thermal	Steam									High
	High-pressure air									High
Chemical	Polymer									Low
	Surfactant									Moderate
	ASP									High

IFT = interfacial tension
WAG = water-alternating-gas
ASP = alkali-surfactant-polymer

1. Change of composition of liquid hydrocarbon.
2. Waterflooding provides the base case for comparison of other methods.
3. Oil stripping occurs as miscibility develops.
4. Condensing and vaporizing exchange.

^ Physical effects of EOR methods. EOR methods generate various physical effects that help recover remaining oil (shaded boxes). The incremental recovery factor (*right*) has a large range of values when compared with waterflooding, which is typically not considered an EOR method.



^ Miscible water-alternating-gas (WAG) process. In a miscible WAG process, an injected gas—CO_2 in this case—mixes with reservoir oil and creates an oil bank ahead of the miscible zone. The gas is followed by a slug of water, which improves the mobility ratio of the displacing fluids to avoid fingering. The cycle of gas and water injection can be repeated many times, until a final waterdrive flushes the remaining hydrocarbon, now mixed with CO_2, from the reservoir. Formation heterogeneities, such as a higher permeability streak (darker layer), affect the shapes of the flood fronts.

most researchers think there is a COBR interaction that liberates additional oil (see "On the Road to Recovery," *page 34*).

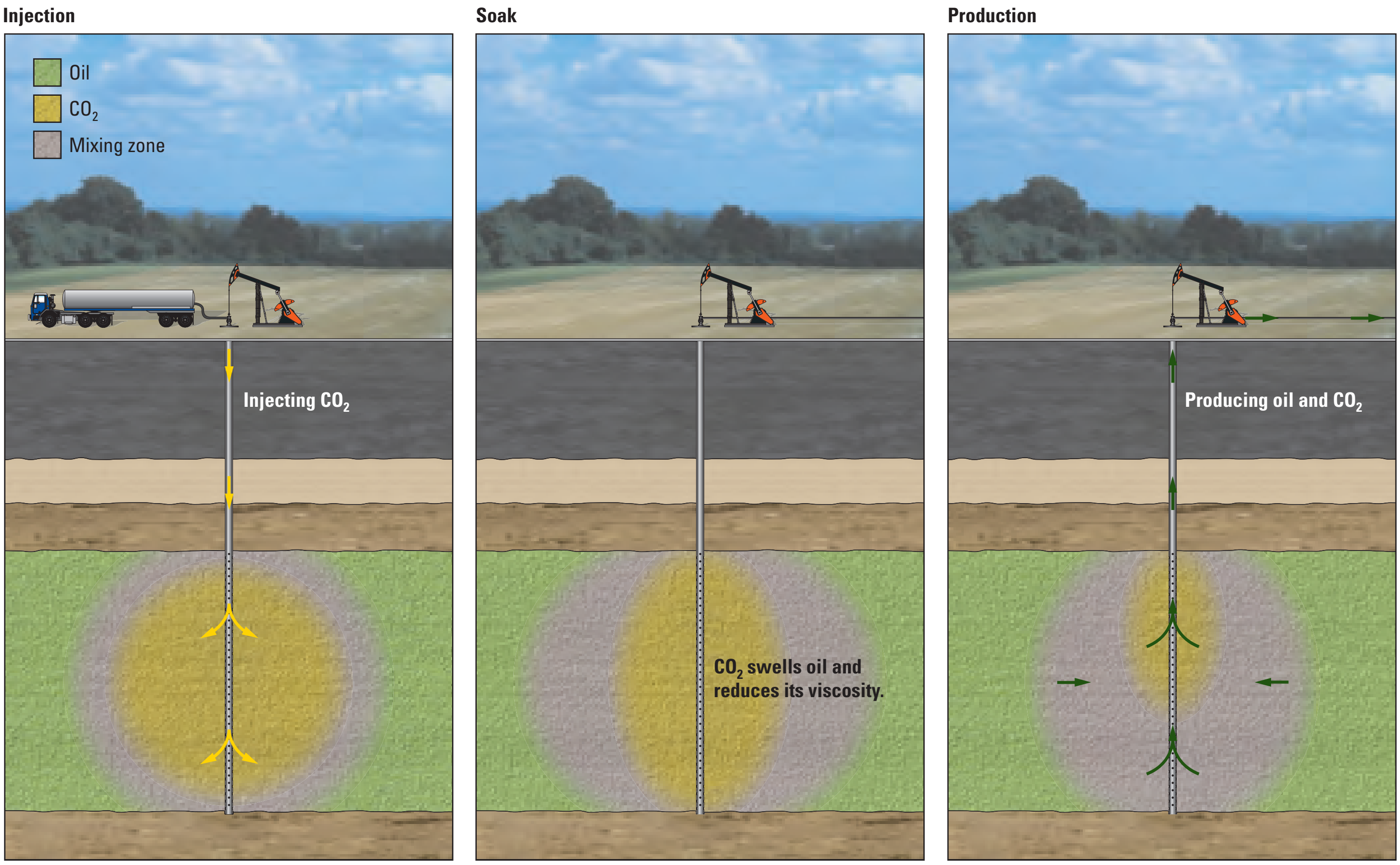
Gasflooding—Historically, gasflooding has often been classified as a secondary or IOR method. It can be a preferred disposal or storage method for associated natural gas when there is no available market, or seasonally when gas demand is lower than supply. But it can also be applied after waterflooding, or in combination with a waterflood, in which case it is considered an EOR method. When performed in conjunction with waterflooding, injection typically alternates between gas and water. The water-alternating-gas (WAG) cycles improve sweep efficiency by increasing the viscosity of the combined flood front (above). In addition, with some fluid compositions and in situ conditions, foam may form, which can further improve the viscosity-related sweep efficiency.

Depending on the pressure, temperature and composition of the gas and oil, injection can be under either immiscible or miscible conditions. In an immiscible flood, gas and oil remain distinct phases. Gas invades the rock as a nonwetting phase, displacing oil from the largest pores first. However, when they are miscible, gas and oil form one phase. This mixing typically causes the oil volume to swell while lowering the interfacial tension between the oil phase and water. Displacement by miscible-gas injection can be highly efficient for recovering oil.

The rock wettability also has an impact on oil recovery by miscible flooding. In a laboratory core study, the best waterflood oil recovery was in mixed-wet rocks, followed by intermediate-wet and water-wet rocks, with oil-wet rocks having the least waterflood oil recovery.[19] For a miscible gasflood after waterflooding, the greatest amount of remaining oil was recovered from the oil-wet core, suggesting that the miscible process could be considered in place of a waterflood.[20] Both the intermediate-wet and mixed-wet rocks had high overall recovery from the combined waterflood and miscible gasflood.

Under some conditions, the fluids are termed multiple-contact miscible. In this case, when they first contact one another, gas and oil are not miscible. However, light components from the oil enter the gas phase, and the heavy, long-chain hydrocarbons from the gas enter the liquid phase. As the front contacts fresh oil, more components are exchanged, until the gas and the oil reach compositions that are miscible.[21]

Various gases are used as EOR injectants. Natural gas—produced from the same or a neighboring field—has already been mentioned as one source. Methane or methane enriched with light ends is also used. A local supply of flue gas, such as exhaust gas from a power plant, can be utilized if the transport costs are low enough. Nitrogen,



^ Cyclic gas injection. In a single-well process, a gas such as CO_2 is injected into the near-well region for a brief period of hours or days (*left*). During a long soak period of days or weeks (*middle*), the miscible gas mixes with the oil in place, swelling it and reducing its viscosity. Then the well is produced for an extended period of time (*right*), taking advantage of the increased pressure from the injected fluids and the change in properties of the oil. The cycle is typically repeated.

which is generally separated from air on location, is another injection gas.

Most gas-injection EOR projects in operation today use CO_2 as the injection gas (above).[22] In Texas, New Mexico and Oklahoma, USA, naturally occurring CO_2 is produced and piped to oil fields. Recently, considerable interest has arisen in using CO_2 injection as a way both to increase oil recovery and to sequester anthropogenic sources of this greenhouse gas. This option generally requires proximity between the source factory and an oil field suitable for CO_2 injection.

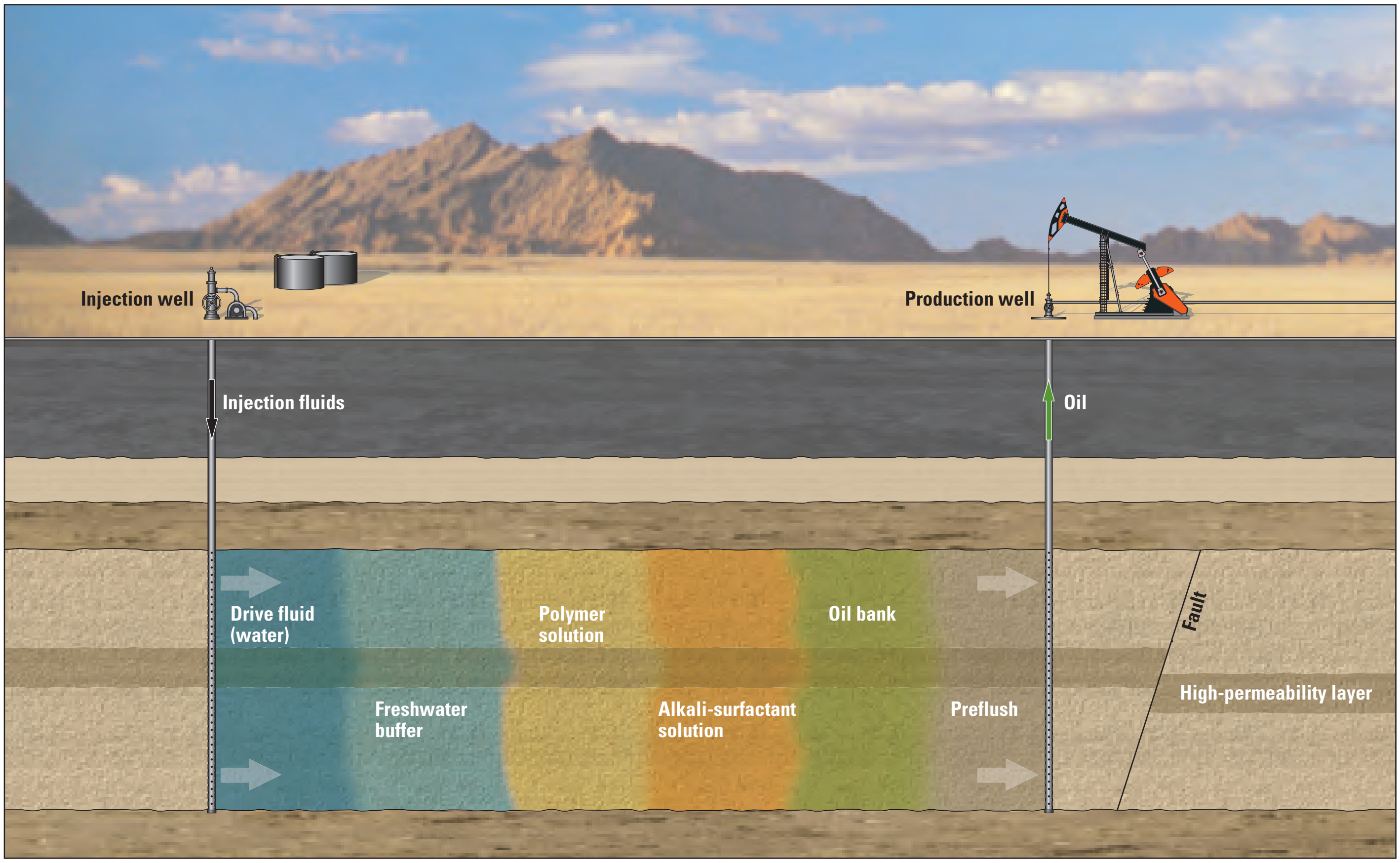
Chemical flooding—Many types of chemicals are injected to recover oil, but they generally fall within one of three groups: polymers, surfactants and alkalis. There are few projects active today, but historically, polymer injection has been applied significantly more often than the other two methods.[23] Modern chemical floods can be highly successful at displacing remaining oil, with oil recovery in the high 90% range reported in the laboratory and the field.

Long-chain polymers are injected along with water or other flooding agents to improve the viscosity ratio, thereby decreasing viscous fingering. Polymer injection is used both for near-well conformance control and for formation sweep control.

Surfactant chemicals are medium- to long-chain molecules that have both a hydrophilic and a hydrophobic section. Thus, the molecules accumulate at the oil/water interface and lower the IFT between the phases. Since capillary forces prevent oil from moving through water-wet restrictions, such as pore throats, decreasing such forces can increase recovery. When the capillary number, or ratio between viscous and capillary forces, is high, viscous forces dominate and remaining oil can move. This also applies in a gravity-dominated displacement, where the Bond number, or ratio of gravity to capillary forces, needs to be high to overcome capillary trapping. Although the price of surfactants has declined relative to the price of crude oil since the 1980s, they remain among the costliest EOR injectants.

An alternative to surfactants is high-pH, alkaline chemicals. If the oil contains sufficient concentration of petroleum acids of the right type, the alkali will react in situ to form soaps, which are also surface active. The objective is the same as a surfactant flood, but since the surfactant

19. Rao DN, Girard M and Sayegh SG: "The Influence of Reservoir Wettability on Waterflood and Miscible Flood Performance," *Journal of Canadian Petroleum Technology* 31, no. 6 (June 1992): 47–55.
20. Rao et al, reference 19.
21. There are three ways for mass transfer between fluids to occur: The fluids can be soluble in one another, they can diffuse into one another due to random motion, or a concentration gradient can drive one into the other through dispersion. In a CO_2-crude oil system, solubility is the main driver.
22. Moritis (2010), reference 2.
23. Moritis (2010), reference 2.



^ Alkali-surfactant-polymer flood. An ASP flood includes several flood stages. A brine preflush is sometimes used to change the salinity or other rock or fluid properties. The first chemical slug injected is a combination of alkali and surfactant. That slug mixes with the oil and changes its properties, decreasing the IFT and altering the rock wettability. These effects mobilize more oil. A polymer slug follows to improve the mobility differential between the oil and the injected fluids. This slug is typically followed by a freshwater slug to optimize recovery of the chemicals, and then a flood with drive water. Gravity over- or underride and formation heterogeneities, such as a higher permeability streak (darker layer), affect the shapes of the flood fronts.

characteristics of the soap are not designed for the system, recovery may not be as high as with surfactants chosen specifically for the field.

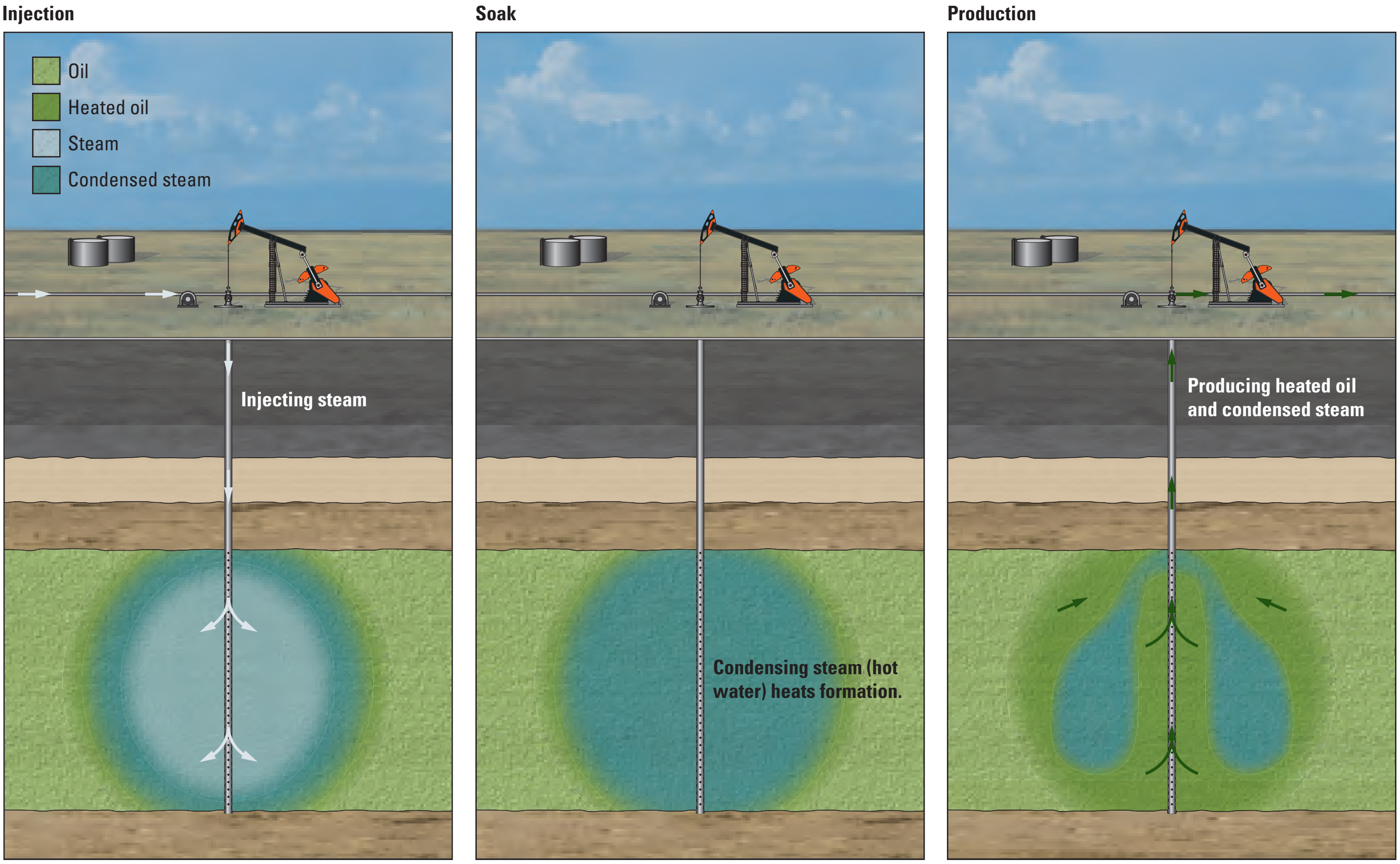
Combinations of these chemical methods have become more common. An early combination used in several fields was surfactant-polymer flooding, also called micellar-polymer flooding. A slug of surfactant is injected to mobilize the oil, followed by a polymer flood to prevent viscous fingering. Recently, a combination of all three types of injectants has shown significant promise. In alkali-surfactant-polymer (ASP) flooding, operators inject a tailored mix of an alkaline compound and surfactants chosen for the specific COBR system, followed by polymer slugs for mobility control (above). Properly formulated, an ASP flood combines the best of the three chemical methods to optimize recovery (see "Laboratory Predesign for an ASP Flood," *page 29*).[24]

Lower IFT can also be obtained through microbial EOR. The research emphasis today is on finding microbes already present in the formation that have favorable properties for interfacial activity and then injecting nutrients favored by those microbes. This leads to their proliferation in situ, increasing the microbial action that generates lower IFT for the oil/water system. Microbial EOR has not been applied often.[25]

Thermal methods—Typically, heavy oil is mobilized by adding heat to a reservoir to decrease oil viscosity. Viscosity of very heavy oils can drop by a factor ranging from 100 to 1,000 when heated from about 40°C to 150°C [100°F to 300°F].[26] Thermal methods include steamfloods, hot waterfloods, electrical heating and combustion. Steam has greater heat content than hot water, but they both serve similar purposes in EOR. Electrical heating has been tested in several field trials, but has not otherwise been implemented.[27] Although in situ oil combustion is used, steamflooding is the predominant thermal method.[28]

New wells in a heavy-oil reservoir often begin production using cyclic steam injection to improve oil mobility in the near-well region (next page).[29] In this single-well process, a slug of steam is injected into the formation, and, after a soak phase to allow heat transfer to the reservoir, the well is produced. The cycle repeats, often until steam heats a sufficient formation volume such that the well can be incorporated into a pattern steamflood.

The pattern in a heavy-oil field typically has relatively small well spacings. Injected steam heats and thins the heavy oil and displaces it to production wells.



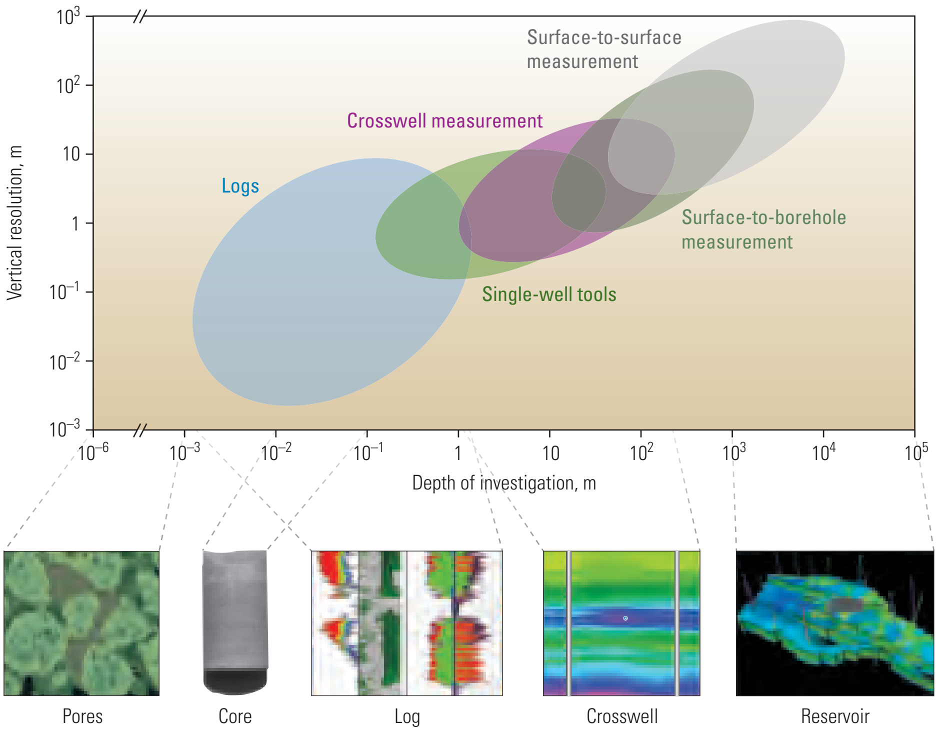
^ Cyclic steam injection. This single-well process injects steam into the near-well region for days to weeks (*left*). The soak period lasts a few days (*middle*) during which time the heat reduces the oil viscosity. Production follows for an extended period of time (*right*). The cycle can repeat, or the well can be converted to an injection well in a pattern flood.

Thermally assisted gas-oil gravity drainage is suited for heavy oil in fractured formations. Steam injected into the fracture system heats the formation, thinning the oil so it flows more easily into the fractures. The steam also applies a gas gradient across the matrix blocks so that the oil in the formation drains by gravity.

In Canada, a dual horizontal-well system called steam-assisted gravity drainage (SAGD) has been successful. Steam is injected into an upper horizontal well, creating a hot zone. The hot oil drains to and is produced through a lower, parallel wellbore.

Oil can also be heated by combusting it in situ. At a controlled rate, operators inject a gas containing oxygen, most commonly air, into an oil-bearing formation, and then ignite it to begin combustion. The combustion front is narrow and moves slowly away from the injection well. Hot combustion gases flow ahead of the fire zone and strip light ends from the oil. This process forms an oil bank. The remaining oil saturation is thermally cracked as the hot front approaches, and the lighter mobile oil advances. Residual coke coats the rock grains and becomes fuel for the combustion front. A combustion flood can be combined with water injection, increasing the amount of steam in the gas bank. In situ combustion has been used in reservoirs containing both heavy and medium-gravity oil. The oldest still-active air-injection project in the US began in 1978 in Buffalo field, South Dakota, USA; incremental production due to air injection in the field was 18.1 million bbl [2.9 million m^3] in 2009.[30]

24. Hirasaki GJ and Miller CA: “Recent Advances in Surfactant EOR,” paper SPE 115386, presented at the SPE Annual Technical Conference and Exhibition, Denver, September 21–24, 2008.
25. Moritis (2010), reference 2.
26. Braden WB: “A Viscosity-Temperature Correlation at Atmospheric Pressure for Gas-Free Oils,” *Journal of Petroleum Technology* 18, no. 11 (November 1966): 1487–1490.
27. For a recent review of electrical heating methods: Das S: “Electro-Magnetic Heating in Viscous Oil Reservoir,” paper SPE/PS/CHOA 117693, presented at the International Thermal Operations and Heavy Oil Symposium, Calgary, October 20–23, 2008.
28. Moritis (2010), reference 2.
29. For more on heavy-oil reservoirs: Alboudwarej H, Felix J, Taylor S, Badry R, Bremner C, Brough B, Skeates C, Baker A, Palmer D, Pattison K, Beshry M, Krawchuk P, Brown G, Calvo R, Cañas Triana JA, Hathcock R, Koerner K, Hughes T, Kundu D, López de Cárdenas J and West C: “Highlighting Heavy Oil,” *Oilfield Review* 18, no. 2 (Summer 2006): 34–53.
30. Kumar VK, Gutiérrez D, Thies BP and Cantrell C: “30 Years of Successful High-Pressure Air Injection: Performance Evaluation of Buffalo Field, South Dakota,” paper SPE 133494, presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, September 19–22, 2010.



^ Scales of evaluation for EOR. Tools and measurements used to evaluate formations for EOR projects in the field (*top*) and in the laboratory or office (*bottom*) span a wide range of scales with various resolutions. Designs for EOR processes should consider both microscopic and macroscopic sweep, so an evaluation must include pore-scale through reservoir-scale measurements and analysis.

Selecting an EOR Method

Choosing a method or combination of methods to use for EOR is best done based on a detailed study of each specific field. Since most EOR techniques involve complex physics, the reservoir must be characterized at many levels (above). Pore morphology affects microscopic displacement efficiency. Formation properties and heterogeneities influence macroscopic sweep, whether they are at log scale, interwell scale or fieldwide. Thus, the evaluation proceeds in stages with the objective of reducing the uncertainty that application of an EOR technique will achieve technical and economic success.

The methodology starts with relatively inexpensive activities based in the office or the laboratory, progressing to field trials and implementation, which are more expensive and time-consuming. However, at any stage, if the project does not meet the company's technical and financial criteria for that stage, the project does not proceed further. The project team can either iterate earlier steps to find a better solution with less uncertainty or abandon the project.

The first step is to gather as much data about the reservoir as possible and develop a coherent package of information. This can be compared with screening criteria for various recovery methods. These criteria, based on past field successes and failures, can provide a positive match for some EOR technologies. Because tailored chemicals are expanding ranges of applicability for chemical methods, the asset team evaluating the methods should review the current literature and consult with researchers and chemical manufacturers. In addition, former limits on oil gravity and viscosity and brine salinity are now being broken by synthetic surfactants, which are often available at lower cost than previously possible.[31]

Once the number of feasible EOR technologies has been narrowed, the evaluation typically moves into the laboratory. Physical properties of the fluids and combinations of fluids, including the crude oil and formation water, have to be confirmed for the chosen technique. It is important to examine not only the positive aspects, such as miscibility and wettability alteration, which are desired, but also any negative ones, such as scaling or wax dropout, which should be avoided. Next, to investigate fluid/solid properties such as adsorption, the chemicals are mixed with grains that are representative of the formation. Then, flow studies are conducted, using either sandpacks in a slim tube or cores, or both. At each of these laboratory stages, potential EOR methods can be eliminated or tailored for the specific field application (next page).

After engineers and geoscientists evaluate the field history, they can develop updated static and dynamic reservoir models. Armed with results from flow and other laboratory tests, modeling experts can simulate the effect of the EOR method in the dynamic model to predict expected recovery. For example, the ECLIPSE reservoir simulator handles most combinations of chemical floods, such as the ASP method.[32] Simulation includes finding an appropriate well configuration, spacing and pattern, as well as the proper injectants and injection strategy.

Major unknowns, such as formation heterogeneity, are evaluated using multiple iterations of the simulator with different model parameters. Operators compare expected supply costs and project economics to the base case of continued production without an EOR technique. If the simulation indicates the project meets company technical and financial requirements, then it can be used to design the next stage: field tests.

Field pilots should be designed to answer specific questions. The pilot objectives may include the following assessment of the EOR process for full-field development:

- Evaluate recovery efficiency.
- Assess effects of reservoir geology on performance.
- Reduce technical and economic risk in production forecasts.
- Obtain data to calibrate reservoir-simulation models.
- Identify operational issues and concerns.
- Assess the effect of development options on recovery.
- Assess environmental impact.
- Evaluate operating strategy to improve economics and recovery.[33]

EOR pilots range from single-well tests, with injection only or including production, to single-pattern or multiple-pattern pilots; cost and complexity increase generally in that order. A small, single-well injection pilot may be designed simply to assess fluid injectivity. More complex pilots may test aspects of areal and vertical sweep, gravity override, channeling and viscous fingering.[34]

Planning for pilots must have a focus on fast and efficient data collection to answer the questions discussed previously. These data come from surface and subsurface monitoring, and the plan may also incorporate monitoring wells drilled to obtain additional data at specific points in the field. Time is also a consideration: Sufficient time must be allowed for the flood front to progress through the pilot. In a recent listing of more than

20 ExxonMobil EOR pilot tests, only one test was completed within one calendar year and several lasted for three or more years.[35]

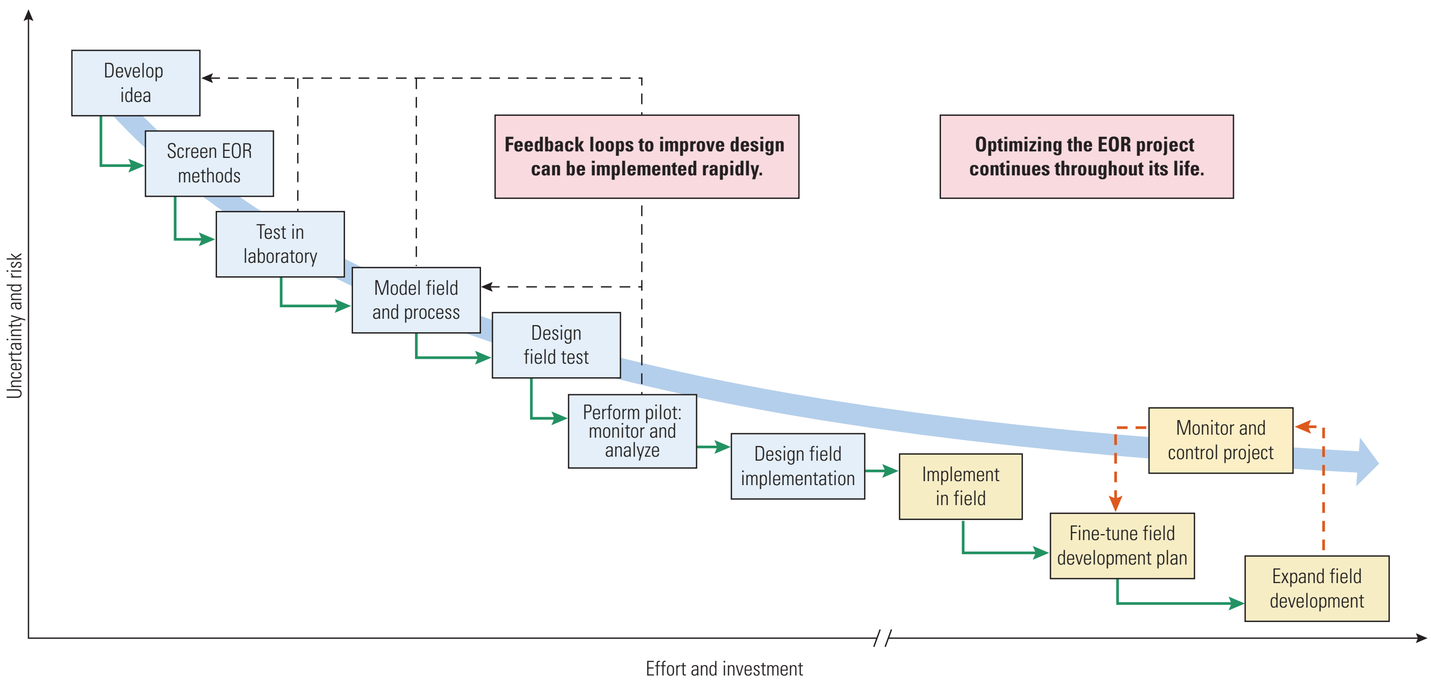
New applications of technologies also expand the options for EOR methods. For example, in a field in the Middle East, the operator planned to use thermally assisted gas-oil gravity drainage for a fractured, heavy-oil reservoir. The operator wanted to monitor the position of the oil rim between gas and water legs, but the formation temperature was beyond the operating range of permanent electronic gauges. Schlumberger placed into the wellbore a U-tube that contained a Sensa fiber-optic monitoring system to measure the tube temperature profile. The U-tube is filled from surface with cool water; the rate that it warms in the wellbore depends on the properties of the surrounding fluids. The temperature profile response allows discrimination of the fluid levels, and the measurement can be rapidly repeated. This fit-for-purpose solution enabled evaluation of the EOR prospect.

Applying EOR to offshore fields, particularly those in deep water, involves additional concerns. It is considerably more expensive to drill offshore wells, and the surface facilities have space and weight constraints not found onshore, except for those in environmentally fragile areas. High well cost means interwell spacing is larger. This spacing adversely impacts a company's ability to acquire data and adequately characterize the reservoir, and also increases the time needed for an EOR-related response to reach production wells. The constraints on facilities often mean original equipment on a platform has to be reengineered to make space and allow for the weight of EOR-related equipment, such as devices used for injectant mixing and handling, water separation, treatment and disposal, and gas handling and compression. Regardless of the EOR method, safe operations must be assured.[36] A number of EOR projects or pilots have been performed offshore, including gas injection and WAG, chemical flooding and even steamflooding.[37]

On land or offshore, if a small pilot indicates a probability of successful implementation, it might be expanded to include more patterns. This expansion would provide additional information about the behavior of the EOR method in a larger and possibly more heterogeneous area. The goal of all piloting is either to reduce the risk sufficiently to be able to implement an EOR method in all or at least a substantial part of the field, or to eliminate it as incompatible with company goals.

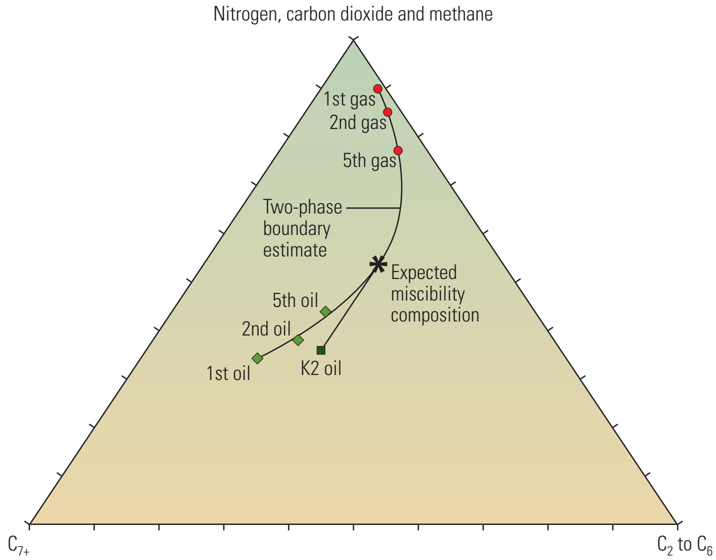
Evaluating Miscibility

The K2 field in the Gulf of Mexico about 175 mi [280 km] south of New Orleans is a large, deepwater, subsalt Miocene-age field.[38] First oil from subsea production wells began in May 2005. The



^ EOR roadmap. The objective of an evaluation of EOR methods is to reduce reservoir uncertainties and economic risk. The evaluation begins by screening based mostly on existing information, comparing the subject field to known successes of various EOR methods in other fields. If the project passes one step, it moves to the next, such as laboratory tests, then field modeling. If the project does not pass a technical or economic hurdle, it can be abandoned or the process can return to an earlier step to reevaluate that or another EOR method. When sufficient confidence has been achieved, the operator designs and implements a field pilot, with possible eventual expansion to full or partial-field implementation. The horizontal axis indicates a sequential process, but it also indicates generally increasing investment required to complete each step going from developing the ideas on the left to field implementation on the right.

31. Yang H, Britton C, Liyanage PJ, Solairaj S, Kim DH, Nguyen Q, Weerasooriya U and Pope G: "Low-Cost, High-Performance Chemicals for Enhanced Oil Recovery," paper SPE 129978, presented at the SPE Improved Oil Recovery Symposium, Tulsa, April 24–28, 2010.
32. Fadili A, Kristensen MR and Moreno J: "Smart Integrated Chemical EOR Simulation," paper IPTC 13762, presented at the International Petroleum Technology Conference, Doha, December 7–9, 2009.
33. Adapted from Teletzke GF, Wattenbarger RC and Wilkinson JR: "Enhanced Oil Recovery Pilot Testing Best Practices," *SPE Reservoir Evaluation & Engineering* 13, no. 1 (February 2010): 143–154.
34. Teletzke et al, reference 33.
35. Teletzke et al, reference 33.
36. Bondor PL, Hite JR and Avasthi SM: "Planning EOR Projects in Offshore Oil Fields," paper SPE 94637, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Rio de Janeiro, June 20–23, 2005.
37. Bondor et al, reference 36.
38. Lim F, Munoz E, Browning B, Joshi N, Jackson C and Smuk S: "Design and Initial Results of EOR and Flow Assurance Laboratory Fluid Testing for K2 Field Development in the Deepwater Gulf of Mexico," paper OTC 19624, presented at the Offshore Technology Conference, Houston, May 5–8, 2008.



^ Forward-contact miscibility test of K2 oil. Results of a miscibility test are typically displayed on a ternary diagram with the composition divided into three pseudocomponents. The top vertex represents the light components, the right vertex is the intermediates, and the left vertex is the heavy components. Each side of the triangle is mixtures of the phases of the adjacent vertices, with tick marks at each 10% change in composition. The K2 field reservoir oil was thoroughly mixed with nitrogen and the resulting phases analyzed. Compositions of the equilibrated first gas and first oil phases are shown. The oil phase was removed isobarically, and fresh oil mixed with the first gas, resulting in the second gas and second oil compositions. The process was repeated five times. The fifth combination had not achieved miscibility, but a smooth curve representing the phase boundary can be estimated from the sequential-mixture phase compositions. A tangent to that boundary curve from the original oil composition indicates the expected composition of the miscible fluid (black asterisk).

field reached a peak oil rate of 40,000 bbl/d [6,400 m^3/d], followed by a continuous decline. The main producing intervals, the M14 and M20 sands, lie more than 25,000 ft [7,600 m] subsea in 4,000 ft [1,200 m] of water. They lack any substantial natural drive mechanisms; production is from pressure depletion. After primary production, a significant quantity of oil will remain.

The operator, Anadarko Petroleum, evaluated the field for its enhanced recovery potential; the screening identified seawater injection and nitrogen injection as the two most technically and economically viable possibilities. Although seawater injection is not usually considered an EOR method, the company gave it the same level of scrutiny as it did the nitrogen injection, because the cost and time required to implement a waterflood in that offshore location are as substantial as they are for a miscible nitrogen flood.

The company has done a waterflood evaluation, as well as an evaluation of flow assurance problems that might arise as a result of either improved recovery method. For example, asphaltene precipitation is a concern in nitrogen flooding. However, this case study focuses on the miscibility of nitrogen injection in the K2 field.

In an immiscible gasflood, the gas remains a distinct phase, and microscopic displacement efficiency is poor. If the gas and oil phases are miscible on first contact, the two become one phase, and the microscopic displacement efficiency can exceed 90% oil recovery. The K2 study evaluated nitrogen injection as a multiple-contact miscible process. When the nitrogen first contacts oil, light ends are stripped from the oil phase into the gas. As the enriched gas front moves ahead, it contacts fresh oil, stripping light ends from that oil and becoming more enriched. This process, called a vaporizing gasdrive, can continue for a number of contacts until the liquid and gas phases become miscible.

This process was evaluated in a laboratory PVT cell with a five-step forward-contact test, using oil from the M14 reservoir and starting with pure nitrogen.[39] After each equilibration step, the compositions of the gas and oil phases were determined. Then the enriched gas phase was equilibrated with fresh oil. Although five steps were insufficient to achieve miscibility, the results could be extrapolated to determine the miscibility composition (above).

Before a forward-contact test can be performed, the minimum miscibility pressure (MMP) must be known. Above this minimum, the gas and oil can achieve miscibility. The MMP condition is determined by slim-tube tests. The slim tube is a long coil of tubing packed with sand, saturated with crude oil, and kept at formation temperature for tests at a series of pressures (next page, bottom). The inside diameter of the tube is large enough that wall effects on flow are negligible, and the flow rate must be low enough that viscous fingering is not a factor. The distinction between miscible and immiscible displacement in the slim-tube test is based on the oil recovery factor after a set injection volume, here taken to be 1.2 pore volumes (PVs) of injection. Recovery significantly less than 90% is considered an immiscible condition, while miscible flooding has high recovery, near or above 90%.

Pure nitrogen was injected into a 60-ft [18-m] slim tube in five tests at different pressures. The objective was to have two tests below the MMP and two above, to establish the trendlines of recovery under those conditions, and then do a final test near the predicted MMP to validate that value. A correlation of MMP for nitrogen and crude oils—which matched all previously published MMP data within 750 psi [5.2 MPa]—predicted an MMP for the K2 crude oil of about 6,500 psi [44.8 MPa].[40]

The first test at a system pressure of 8,000 psi [55.2 MPa] indicated 90% recovery, which fits the criterion for miscible displacement. The second test at 5,500 psi [37.9 MPa] was intended to be below the MMP, but recovery was 84%, which is more likely to be a miscible displacement condition.

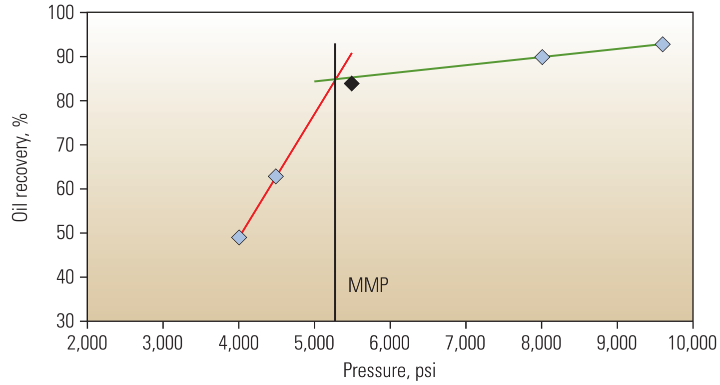
Two tests at lower system pressures, 4,000 and 4,500 psi [27.6 and 31.0 MPa], produced oil recoveries of 49% and 63%, respectively. Based on the recovery, these are considered immiscible displacements. A final test at 9,600 psi [66.2 MPa] produced a recovery of 93%. By

39. In a forward-contact miscibility test, the gas phase is equilibrated with a set quantity of oil. The spent oil is removed and the gas is equilibrated with another set quantity of fresh oil. This step iterates. A backward-contact miscibility test keeps the oil phase and repeatedly exposes it to a set quantity of the original gas phase.
40. Sebastian HM and Lawrence DD: "Nitrogen Minimum Miscibility Pressures," paper SPE/DOE 24134, presented at the SPE/DOE Eighth Symposium on Enhanced Oil Recovery, Tulsa, April 22–24, 1992.
41. Liu S, Zhang DL, Yan W, Puerta M, Hirasaki GJ and Miller CA: "Favorable Attributes of Alkaline-Surfactant-Polymer Flooding," *SPE Journal* 13, no. 1 (March 2008): 5–16.

    The surfactant was supplied by Shell Chemical with Procter and Gamble.
42. A hard brine contains salts of divalent ions such as calcium and magnesium.

extrapolating straight-line trends for the two lowest pressures and the two highest pressures, the MMP was estimated to be about 5,300 psi [36.5 MPa], confirming that the second test was just above the MMP (right).

Anadarko has continued to evaluate the K2 field for its EOR potential, extending the miscible gasflooding studies to include CO_2 injection. The company has not yet decided to implement a field project, but has found value in the laboratory screening.



^ Minimum miscibility evaluation. Oil recoveries from slim-tube tests conducted at different pressures are used to estimate the minimum miscibility pressure of the gas-oil system (blue diamonds). The two highest pressures were selected to be in a miscible condition and the two lowest pressures were selected to be in an immiscible condition. The oil recoveries confirm those choices: miscible displacement results in much higher recoveries than immiscible displacement. The MMP estimate is at the intersection of the trend lines extrapolated from the high pressures and low pressures. It is 5,300 psi in this case, as confirmed by the test conducted at 5,500 psi (black diamond).

Laboratory Predesign for an ASP Flood

Chemical EOR flooding today often uses specially designed fluids, which are manufactured by a number of companies. Thus, an important step in decreasing the uncertainty in project selection is to systematically evaluate the chemicals in laboratory tests, as was done for a West Texas field.

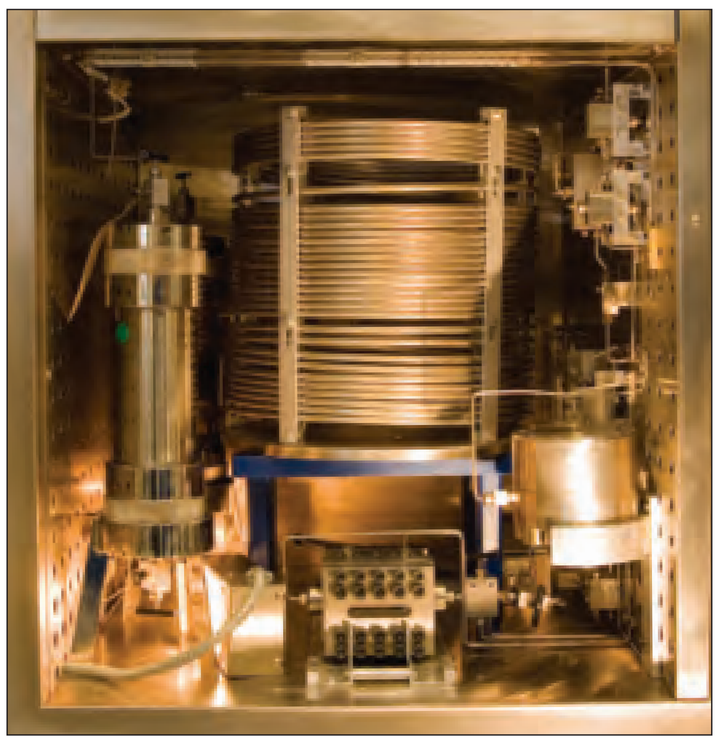
Researchers at Rice University in Houston conducted a series of evaluations of an ASP formulation with a novel surfactant.[41] The results are specific to a crude oil in a dolomite formation from the West Texas field, but they are likely to reflect trends for other ASP applications. The crude oil had an acid number of 0.20 mg/g of potassium hydroxide [KOH], which indicates that exposure to a high pH through injection of an alkali would create sufficient soap to aid the ASP flood. These evaluations provide a good example of steps taken in the laboratory before a field assessment.

Many of the surfactants used in past EOR projects were petroleum sulfonates made from refinery streams or from crude oils in the field, but they tended to form liquid crystals or precipitated in hard brine unless substantial amounts of alcohol or oil were present.[42] Formation of such crystals is undesirable because they can form gels or flocculate, causing plugging, surfactant retention and viscous emulsions.

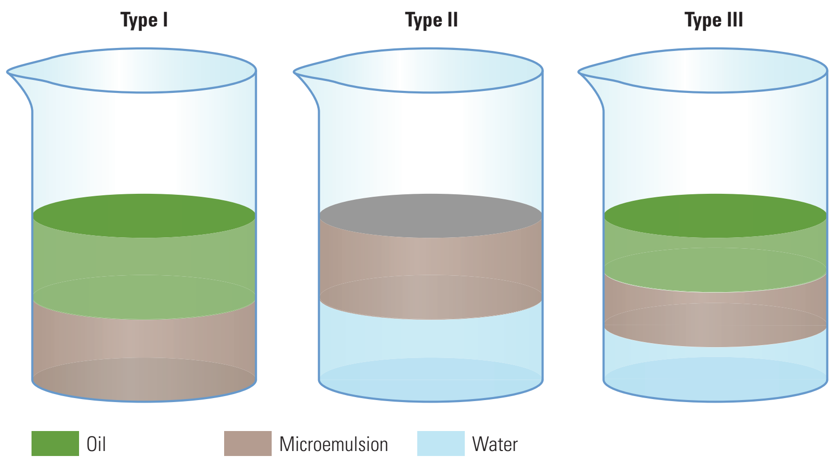
The surfactant used in the evaluation at Rice, termed N67, was a propoxylated sulfate with a slightly branched C_{16} to C_{17} hydrocarbon chain. In contrast to the behavior of petroleum sulfonates, the branches of the hydrocarbon and propylene oxide chains of the tested sulfate mitigate formation of the liquid-crystal phase even in the absence of oil, so the surfactant solution can be injected into the formation as a single-phase micellar solution. Meanwhile, the long, branched hydrocarbon chain gives the N67 surfactant high affinity for the oil, providing low IFT over a substantial range of conditions.

The other ASP injectants used in this evaluation were sodium carbonate [Na_2CO_3] as the alkali, partially hydrolyzed polyacrylamide as the polymer and an internal olefin sulfonate (IOS) as a cosurfactant. IOS is more hydrophilic than N67 and can be used to adjust the conditions for optimal salinity for the mixture.

The first laboratory test was designed to confirm surfactant single-phase behavior in the absence of an oil phase. Each of several concentration ratios of N67 and IOS surfactants was



^ Slim-tube apparatus. The sand-packed metal coil in the middle of the oven is filled with crude oil at reservoir temperature. The coil is positioned so flow is mostly horizontal to minimize gravity effects. A solvent, such as nitrogen gas for the K2 field evaluation, is injected. The coil provides a long flow path so miscibility can develop between the oil and the solvent. After 1.2 PV of solvent is injected, the oil recovery is noted. If miscibility is established, the oil recovery will be near or above 90%. The other components in the oven control flow, temperature and pressure. The coil shown is a 100-ft [30.5-m] slim tube.



^ Winsor emulsion types. A surfactant can form an emulsion in the water phase, leaving behind excess oil (*left*) in a Winsor Type I microemulsion, or in the oil leaving excess water (*center*) in a Type II microemulsion, or it can form a phase whose density is between that of oil and water, leaving excess amounts of both (*right*) in a Type III microemulsion. The lowest IFTs are typically obtained with a Type III microemulsion.

placed in a separate pipette with increasing concentrations of sodium carbonate and sodium chloride. The combinations were mixed and allowed to equilibrate. Single-phase behavior at room temperature existed for salt concentrations up to 4% to 8% by weight—with the limit depending on the surfactant ratio. At the 4/1 ratio of N67 to IOS, the single-phase region extended to about 6%. This is a great improvement over results from past studies, in which use of petroleum sulfonates as injectants required addition of oil or alcohol to obtain a single phase.

The phase behavior of the ASP injectant with oil was next examined using mixtures in pipettes. Ternary mixtures of oil, brine and surfactant can form more than one phase, depending on the brine salinity. At low salinity, a lower-phase microemulsion can form between oil, water and surfactant with a separate excess-oil phase. This is called a Winsor Type I microemulsion.[43] At high salinity, an upper-phase microemulsion (Winsor Type II) can instead form with a separate excess brine phase.

Finally, at intermediate salinity, a middle-phase Winsor Type III microemulsion forms with both an excess-water phase below and an excess-oil phase above (above). A certain value of salinity—termed the optimal salinity—in the Type III range produces a minimum IFT that is equal for both the microemulsion/oil and microemulsion/brine interfaces. Within experimental error, that is also the salinity at which the solubilization ratios of water and oil in the microemulsion are equal.[44] Since phase behavior is easier to test in the laboratory, salinity scans of phase behavior are generally used to determine the optimal salinity (next page). The optimal salinity value depends on the surfactant and oil used and on temperature and pressure.

In an ASP process, near the flood front there is a gradient in the local concentration ratio of surfactant to soap, created as the injected alkali reacts with oil to form the soap. Laboratory tests are designed to ensure that the reservoir salinity is one of the optimal salinities included within the range of ratio gradients. Thus a region of low IFT advances through the reservoir, leaving behind little or no trapped oil.

With the proper choice of chemical concentrations, the optimal salinity of the surfactant-soap combination occurs at a somewhat lower salinity than that of the surfactant alone. Low salinity is advantageous for injection because it reduces surfactant adsorption onto the rock and maintains a single phase for a wider range of chemical concentrations. In the sand-pack test described below, for example, the optimal salinity for the surfactant alone was 5% NaCl, and the surfactant solution was single-phase at that salinity. However, the addition of polymer to provide mobility control shifted the phase equilibrium. A surfactant solution with 4% salinity and added polymer separated into two phases. In contrast, no separation occurred when polymer was added at a lower 2% NaCl concentration.

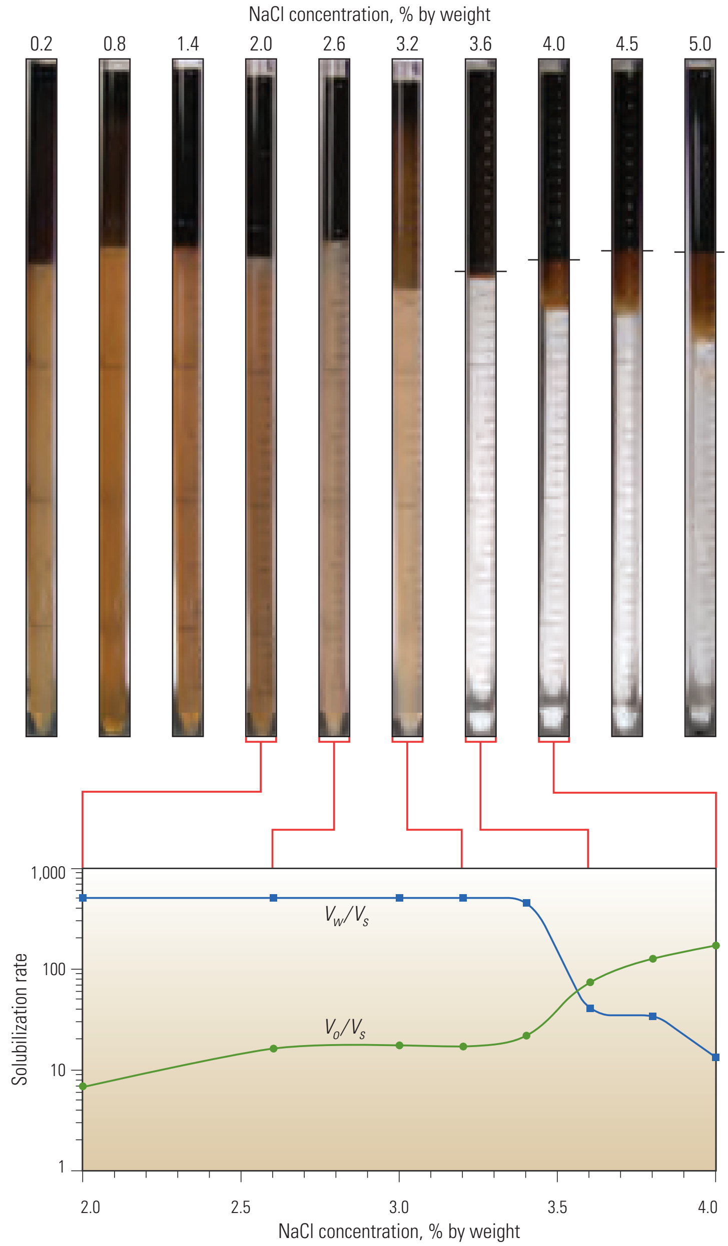
The salinity scan of the N67-IOS system revealed two other interesting behaviors. First, a colloidal dispersion, representing a fourth phase, gradually separated from the lower-phase microemulsion during Type I behavior. This probably resulted from the presence of two types of surfactants—soap and injected surfactant—with very different hydrophilic or hydrophobic properties. Low values of IFT, below 0.01 mN/m, were obtained over a wide range of salinities for these conditions. However, if the dispersion was given an extended time to separate before testing, the IFT remained high. That is, the presence of the fourth phase—and its dispersion in the emulsion—was essential to achieving low IFT values. The reason for this behavior is not well understood.

The second behavior was noted by viewing the pipettes through crossed polarizers: The brine phase exhibited birefringence in concentrations near optimal salinity. This phenomenon is typically indicative of a lamellar liquid crystalline phase, but in this case the aqueous dispersion of the lamellar phase maintained a low viscosity. Even though classic Winsor III behavior was not observed in this case, the IFT reached a minimum at optimal salinity where the surfactant shifted from being preferentially water soluble to preferentially oil soluble.

Surfactants can also adsorb onto a solid surface, but any surfactant remaining there at the end of the process represents a cost to be avoided. The electrical charge on a calcite surface—the primary component of limestones and other carbonate formations—is positive in fluids of neutral pH, but presence of carbonate ions [CO_3^{2-}] reverses the charge to negative. A dolomite surface exhibits similar behavior. The negative charge repulses anionic surfactant ions, such as those in N67 and IOS. A commonly used alkali, sodium hydroxide [NaOH], exhibited surfactant adsorption little different from that of the alkali-free surfactant solution. In contrast, the addition of 1% Na_2CO_3 by weight radically decreased adsorption of both N67 and IOS onto calcite or dolomite powder compared to the case with no alkali, which is a desirable effect because it decreases the amount of surfactant remaining after a flood.

The pipette, IFT and adsorption tests provided guidance to formulate an ASP flood through dolomite sand in a laboratory displacement. The sand was packed into a glass tube with a diameter of 1 in. [2.54 cm] and a length of 1 ft [30.48 cm], which permitted observation of the flood front. The pack was first saturated with 2% by weight NaCl brine, then the West Texas crude oil. After 60-h aging at 60°C [140°F] to alter the dolomite wettability, the pack was cooled to room temperature and waterflooded, reducing oil saturation to 18%.

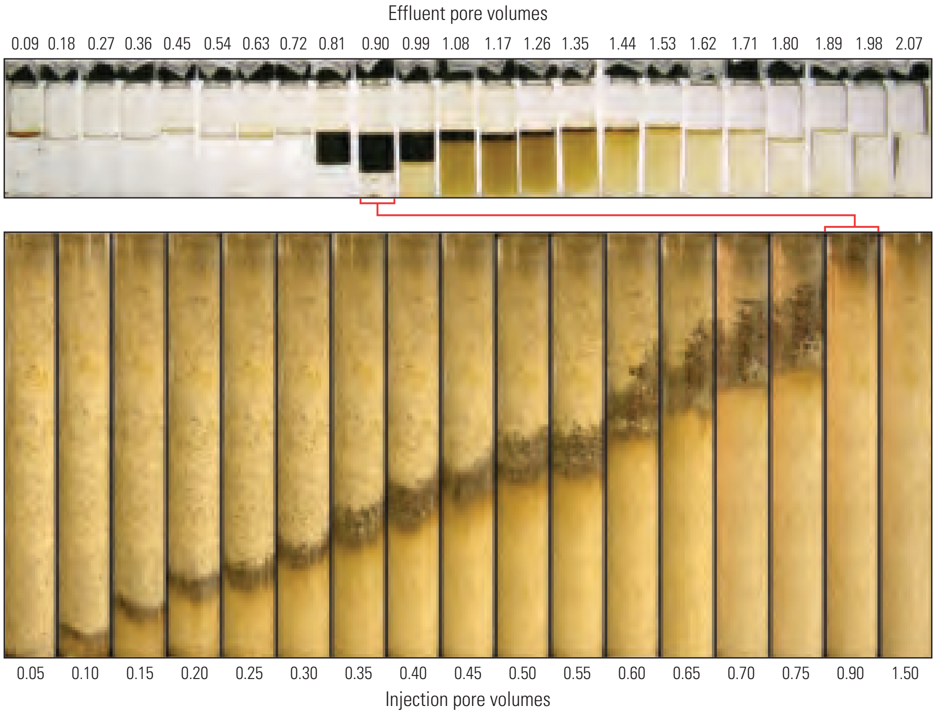
The pack was then flooded with the ASP solution. The first slug, amounting to 0.5 pore volume (PV), contained the N67-IOS blend, sodium carbonate, sodium chloride and polymer. This was followed by a 1-PV slug of polymer and sodium chloride. The viscosity of both the ASP slug and the polymer chaser was 45 cP [0.045 Pa.s], to match or exceed the effective viscosity of the oil bank formed ahead of the flood front. As indicated above, the 2% by weight concentration of sodium chloride was below the optimal salinity of 5% for the injected surfactant system.



^ Salinity scans. Scientists filled pipettes with known amounts of crude oil and brine containing an alkali-surfactant blend, 1% Na_2CO_3 and a variety of NaCl concentrations (*top*). At NaCl concentrations up to 3.2%, a Type I microemulsion forms (brownish water phase); above that concentration there is a transition to Type III behavior, with the upper boundary of the middle phase marked (black lines). For each pipette test, the volume of surfactant V_s is known. The volume of water in the microemulsion phase V_w and the volume of oil in the microemulsion phase V_o are determined, and their ratios to V_s are indicated on a solubilization plot (*bottom*). At a certain NaCl concentration, the solubilization ratios for water and oil are equal. This value, about 3.5% here, is the optimal salinity, which has the lowest IFT. (Photographs courtesy of George J. Hirasaki and Clarence A. Miller.)

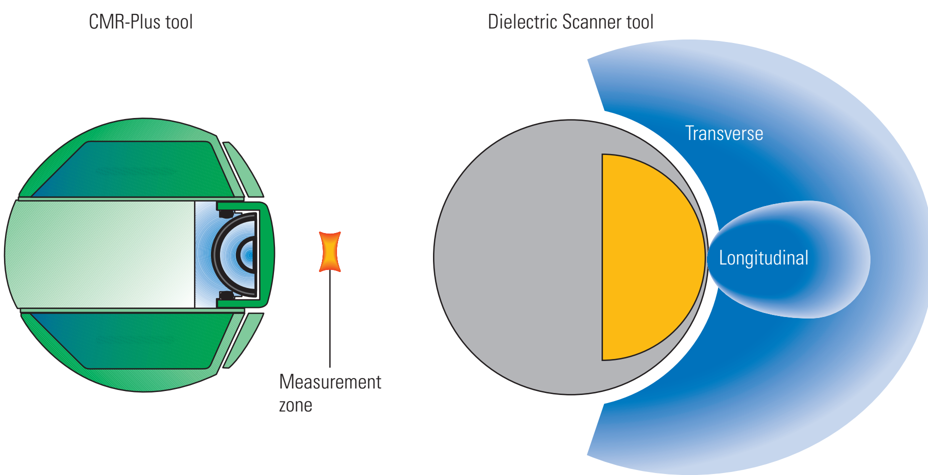
43. Winsor PA: "Hydrotropy, Solubilisation and Related Emulsification Processes," *Transactions of the Faraday Society* 44 (1948): 376–398.

44. The solubilization ratio of a component is the ratio of the volume of that component that is in the microemulsion phase to the volume of solute, which in this case is the surfactant.



^ Formation of an oil bank in a dolomite sand pack. An optimized ASP formulation is injected into the bottom of a 1-in. diameter glass tube (*bottom*). All the images are of the same tube, taken after injecting sequentially increasing pore volumes of the ASP solution. The alkali and surfactant form an oil bank (dark band) that moves ahead of the chemical flood front. Most of the oil production (black liquid, *top*) occurs when this bank breaks through, as shown in the 0.81 PV effluent beaker. The sandpack at 0.90 PV injection shows most of the core has been cleared of oil, and the 0.90 PV effluent vial shows, at about this same time, significant oil is still being produced. The surfactant solution flushes additional oil until about 1.5 PV have been injected. (Photographs courtesy of George J. Hirasaki and Clarence A. Miller.)

The ASP flood clearly showed formation of an oil bank (above). Breakthrough occurred at about 0.8 PV. Most oil was recovered by about 1 PV injection, although the flood continued to produce some oil until about 1.5 PV. The process recovered 98% of the oil remaining after the waterflood, demonstrating the potential of this EOR method.



^ Logging tool sensitivity. The CMR-Plus logging tool focuses its measurement about 1.1 in. [2.8 cm] into the formation in a region that is about 1-in. [2.5-cm] square (*left*). The measurement zone extends about 6 in. [15 cm] along the tool axis. The Dielectric Scanner tool generates a transverse field, which has a toroidal shape wrapping around the tool sensors, and a longitudinal field, which has a teardrop shape in the measurement plane (*right*). The intersection of these two fields provides a depth of investigation up to 4 in. [10 cm] with a vertical resolution up to about 1 in.

Rapid Downhole EOR Test

Once an EOR method has been evaluated through laboratory testing and shown to meet acceptance criteria, the next step is to test it in the field. The first step may be a simple, single-well injectivity test, whose primary function is to establish that the fluids can be injected into the target formation at acceptable rates.

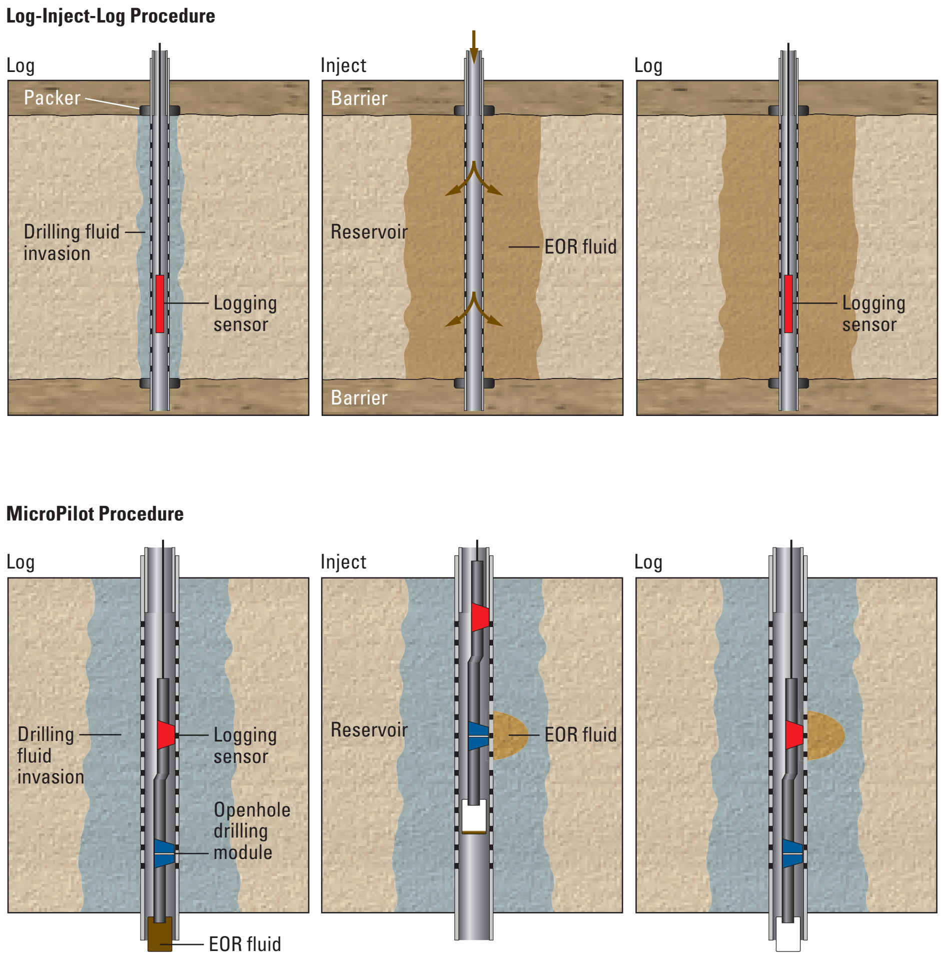
Another single-well test that requires more time, but returns a greater amount of information, is a single-well tracer test. This test uses a chemical tracer soluble in both oil and water, such as certain esters, that reacts in the formation to form a water-soluble component, such as an alcohol. That tracer is injected as a slug, and then left in place for a several-day soak period to allow some of the tracer to react. The well is put on production, and the separation in production peaks between the water- and oil-soluble phases can be used to determine the residual oil saturation. Complete interpretation of pilot results requires information about the rock properties.

A new method of single-well testing assessed the effectiveness of an ASP formulation for a well in a field in Oman.[45] Petroleum Development Oman (PDO) operates this sandstone field, which produces medium-gravity oil from a formation having 3,500 to 4,000 mD/cP [3.5×10^6 to 4×10^6 mD/Pa.s] drawdown mobility. The operator wanted to evaluate the ASP in the field, but sought a quicker method than a traditional log-inject-log process.

In a log-inject-log procedure, an initial logging run establishes the properties of the formation interval, in particular, the oil saturation (next page). After injection of one or more fluids, a second logging run measures the oil saturation again to determine the effectiveness of the injectant for EOR. Typically, a single-well log-inject-log pilot floods an entire interval to about 10 ft [3 m] from the wellbore, requiring large volumes of injectant—and the associated surface facilities to mix and process it—in addition to an extended injection time.

After exchanging ideas with PDO on how to improve on these lengthy single-well pilots, Schlumberger brought together several advances in logging technology to decrease the amount of injectant used to a relatively small volume. The injectant can be readily premixed.

The MicroPilot small-scale EOR evaluation uses a small volume of injectant, up to the 6-galUS [22.7-L] capacity of a downhole fluid sample chamber. Because the injectant volume is so small, the total time spent on the procedure—two to three days—is much shorter than the weeks or so necessary for a typical single-well



^ Single-well pilot testing using log-inject-log procedure. In a typical log-inject-log procedure (*top*), a region of interest is isolated using packers. The interval is logged, then a fluid is injected throughout the zone to an invasion depth of about 10 ft. The same logging suite is run after injection to determine the saturation change in the formation. In a MicroPilot operation, a smaller region of interest is logged (*bottom*). Then the tool is positioned at a station within that region and the drilling module drills a small hole into the formation. The depth of that small injection hole is designed to reach the most sensitive region of the onboard logging tool measurements. An EOR test fluid is injected through that hole. The amount injected is at most a few gallons, carried downhole in sampling bottles. The interval is logged again. Note that the illustrations are not to scale: A log-inject-log procedure typically involves a much larger depth interval than the MicroPilot procedure.

pilot. Although small compared with a typical log-inject-log test, the MicroPilot flood volume is much larger than that of a typical coreflood in a laboratory, allowing for testing of some formation heterogeneity.

The first MicroPilot objective is to inject the fluid at a precise location. The tool uses a drill modified from one proved in service in the CHDT cased hole dynamics tester. Originally designed to drill through casing and cement, the 0.39-in. [1-cm] diameter bit is capable of drilling through mudcake and into the formation to a depth up to 6 in. [15 cm]. The drilling module is combinable with sample chambers from the MDT modular formation dynamics tester family, which transport the fluids downhole. MDT pumpout modules can be used for hole cleaning, formation mobility testing and injecting the fluids, and MDT downhole fluid analysis modules can be used to monitor and analyze the fluids as they are injected or recovered.

Saturation change can be difficult to measure in situ for an EOR process like ASP flooding. The salinity can change radically in formation water, mud filtrate and ASP injectant. In addition, an ASP flood can change the formation wettability, so the Archie saturation exponent n will also change after a successful flood. A saturation measurement based on resistivity is obtained, but it may not provide consistent results before and after injection. However, the CMR-Plus combinable magnetic resonance tool is sensitive to the volume, properties and environment of the fluid (previous page, bottom). Within a certain range of oil viscosity, it may be possible to discriminate

45. Arora S, Horstmann D, Cherukupalli P, Edwards J, Ramamoorthy R, McDonald T, Bradley D, Ayan C, Zaggas J and Cig K: "Single-Well In-Situ Measurement of Residual Oil Saturation After an EOR Chemical Flood," paper SPE 129069, presented at the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, April 11–13, 2010.
Cherukupalli P, Horstman D, Arora S, Ayan C, Cig K, Kristensen M, Ramamoorthy R, Zaggas J and Edwards J: "Analysis and Flow Modeling of Single Well MicroPilot* to Evaluate the Performance of Chemical EOR Agents," paper SPE 136767, presented at the SPE International Petroleum Exhibition and Conference, Abu Dhabi, UAE, November 1–4, 2010.

the oil and water using fluid magnetic resonance relaxation and diffusion measurements. The magnetic fields that define the sampling geometry are unaffected by the fluid exchange.[46] Azimuthal tool geometry focuses the measurement 1.1 in. into the formation on a specific volume that is about 1-in. square by 6-in. long for station measurements, or 7.5-in. [19-cm] long when logged at 150 ft/h [46 m/h]. With the CMR-Plus tool, oil-saturation measurement uncertainty in this formation is 5% within the range of oil saturation from 90% to 0%.

The multifrequency dielectric dispersion measurement available from the Dielectric Scanner tool is also sensitive to the water volume. Close to the wellbore, the 1-GHz measurement has a vertical resolution of 1 in. and is insensitive to IFT changes. The salinity sensitivity of the tool can be independently determined from water saturation using multifrequency data collected at several source-receiver spacings. Water saturation, independent of brine salinity, can be calculated from these measurements in conjunction with a porosity log.

The MicroPilot test in the PDO well showed that ASP injection successfully displaced remaining oil from a waterflooded formation. In the pilot, 11 L [2.9 galUS] of ASP was injected into the small hole created by the CHDT tool. An electrical image from an FMI fullbore formation microimager log clearly showed development of an oil bank and displacement of the residual oil in a roughly circular region centered at the injection hole (next page).

Both the NMR and dielectric measurements indicated a reduction in the remaining oil saturation from 40% to near 0% behind the front. The dielectric measurement also showed the buildup of oil saturation as a bank ahead of the ASP front, which matched the results of an ECLIPSE reservoir model of the injection.

This evaluation was part of a larger study PDO is doing on ASP flooding. In conjunction with Shell Technology Oman, PDO has performed several single-well tracer tests of the same ASP treatment. The degree of desaturation seen in those more extensive field tests was similar to what was seen in the MicroPilot test.[47]

Multiwell ASP pilots have been conducted in the Daqing oil field, Heilongjiang Province, China, which is operated by Daqing Oilfield Company. This multilayered deltaic, lacustrine reservoir is the largest oil field in the People's Republic of China. In four ASP pilot tests, the incremental oil recovery over waterflooding was about 20%, with a chemical cost of US$ 11 to US$ 15/bbl of incremental oil.[48] This field is also the site of the world's largest polymer EOR flood, with more than 20 years of polymer injection in the field.[49] The recovery after polymer flooding exceeds 50%, which Daqing Oilfield Company indicates is a 10% to 15% improvement over conventional waterflood production from these wells.[50]

On the Road to Recovery

Based on current production, the most successful EOR techniques, by far, have been steamflooding and CO_2 flooding, with hydrocarbon gasflooding at a distant third.[51] Combustion and polymer and nitrogen flooding also have produced substantial amounts of additional oil. Other methods are still being tested.

One EOR method that has garnered considerable attention and that has been tested in several pilot studies is low-salinity waterflooding. Most waterfloods use high-salinity brine, and additional oil recovery has been obtained by following that with a low-salinity waterflood.[52] Use of injection water with specially engineered salinity and ion composition has also been referred to as engineered- or smart-water injection.[53]

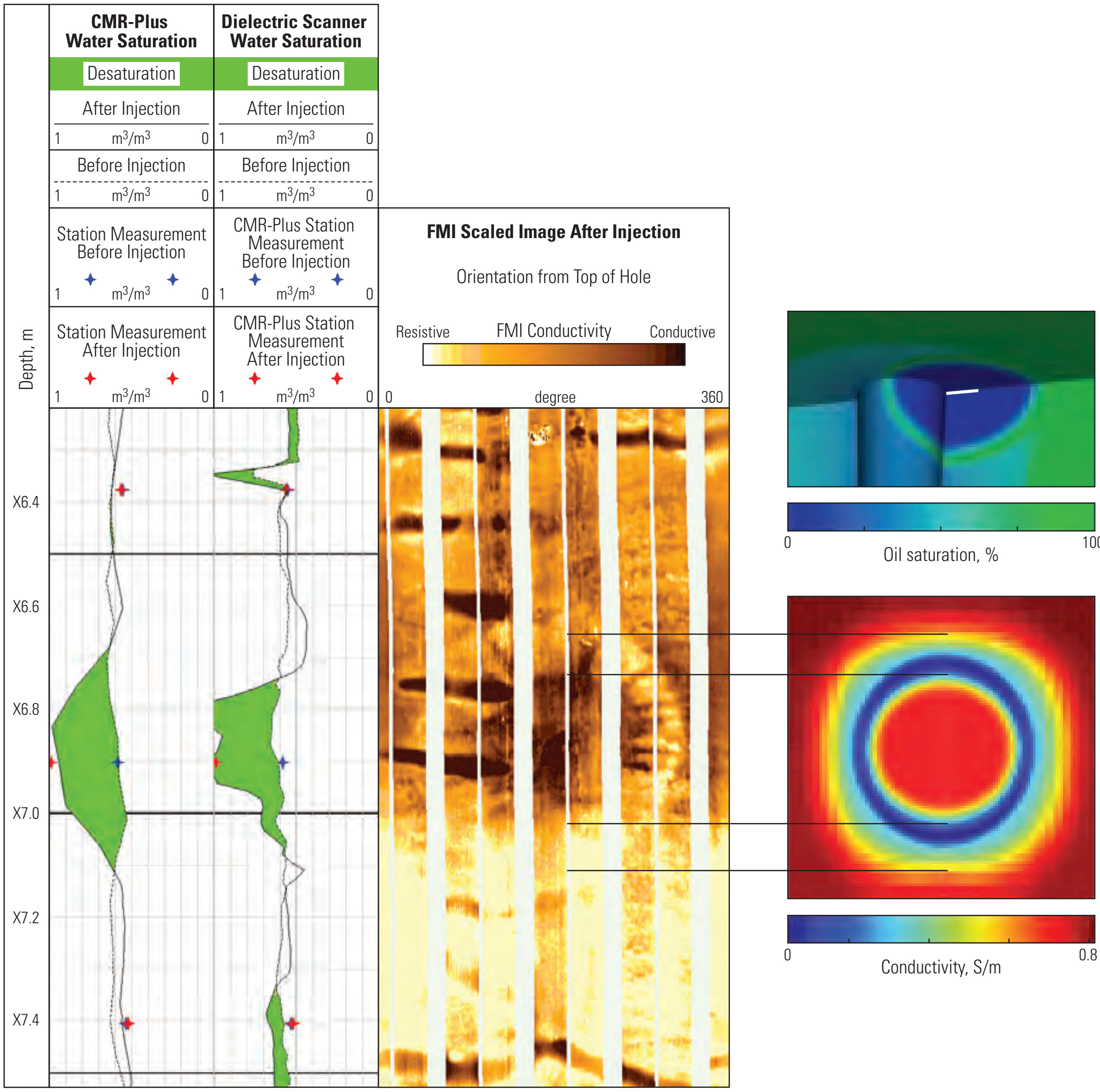
BP piloted the low-salinity method in Endicott field, Alaska, USA.[54] Positive results of laboratory corefloods and several single-well tracer tests were confirmed in a two-well pilot. The original oil saturation in this field was 95%, which was reduced to 41% by a high-salinity waterflood. The water cut at that point was 95%. Next, the operator executed a low-salinity pilot flood. When the low-salinity front broke through at the producer, water cut dropped to 92%. The residual oil saturation is expected to reach 28%, a 13-unit drop in oil saturation.

The mechanism leading to this additional recovery after low-salinity flooding is not yet agreed upon, but some interaction or combination of interactions involving the crude oil, brine and rock is believed to be the cause. Generally, presence of four factors has been thought to be required.[55] The system has to include crude oil: The effect is not seen when a core sample is saturated with refined oil. Formation water must be present. There must be a crude oil/brine interface. Finally, clays must be present: Cores heated to a high temperature to convert and stabilize clays did not show the effect. However, even this list is in flux. Recent work on sandstone and dolomite cores with no clay exhibited increased recovery from low-salinity flooding, which was attributed to dissolution of fines in the formations.[56]

Some field tests of the method by other operators in other locations did not recover sufficient additional oil for this to be an economic process, so the industry is proceeding cautiously.[57] A better understanding of the method's physical and chemical interactions is likely to advance this technique.

A cutting-edge method uses nanoparticles designed specifically for EOR. Their surfaces are engineered to make them move preferentially to oil/water interfaces and mobilize additional oil.[58] Much of the work on nanoparticles for hydrocarbon recovery is still in the laboratory stage.

46. Wettability change brought about by ASP injection can change the NMR response in a way that may make it difficult to measure the saturation change. Laboratory measurements can indicate whether the method will work in a given situation.
47. Stoll WM, al Shureqi H, Finol J, Al-Harthy SAA, Oyemade S, de Kruijf A, van Wunnik J, Arkesteijn F, Bouwmeester R and Faber MJ: "Alkaline-Surfactant-Polymer Flood: From the Laboratory to the Field," paper SPE 129164, presented at the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, April 11–13, 2010.
48. Shutang G and Qiang G: "Recent Progress and Evaluation of ASP Flooding for EOR in Daqing Oil Field," paper SPE 127714, presented at the SPE EOR Conference at Oil and Gas West Asia, Muscat, Oman, April 11–13, 2010.
49. He L, Jinling L, Jidong Y, Wenjun W, Yongchun Z and Liqun Z: "Successful Practices and Development of Polymer Flooding in Daqing Oilfield," paper SPE 123975, presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, August 4–6, 2009.
50. He et al, reference 49.
51. Moritis (2010), reference 2.
52. Tang GQ and Morrow NR: "Salinity, Temperature, Oil Composition, and Oil Recovery by Waterflooding," *SPE Reservoir Engineering* 12, no. 4 (November 1997): 269–276.
53. RezaeiDoust A, Puntervold T, Strand S and Austad T: "Smart Water as Wettability Modifier in Carbonate and Sandstone: A Discussion of Similarities/Differences in the Chemical Mechanisms," *Energy & Fuels* 23, no. 9 (September 17, 2009): 4479–4485.
54. Seccombe et al, reference 18.
55. Pu H, Xie X, Yin P and Morrow NR: "Low Salinity Waterflooding and Mineral Dissolution," paper SPE 134042, presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, September 19–22, 2010.
56. Pu et al, reference 55.
57. Skrettingland K, Holt T, Tweheyo MT and Skjevrak I: "Snorre Low Salinity Water Injection—Core Flooding Experiments and Single Well Field Pilot," paper SPE 129877, presented at the SPE Improved Oil Recovery Symposium, Tulsa, April 24–28, 2010.
58. For example: Onyekonwu MO and Ogolo NA: "Investigating the Use of Nanoparticles in Enhancing Oil Recovery," paper SPE 140744, presented at the 34th Annual SPE International Conference and Exhibition, Tinapa-Calabar, Nigeria, July 31–August 7, 2010.
59. Felber BJ: "Selected U.S. Department of Energy EOR Technology Applications," paper SPE 89452, presented at the SPE/DOE Fourteenth Symposium on Improved Oil Recovery, Tulsa, April 17–21, 2004.
60. Vega B, O'Brien WJ and Kovscek AR: "Experimental Investigation of Oil Recovery From Siliceous Shale by Miscible CO_2 Injection," paper SPE 135627, presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy, September 19–22, 2010.
61. For an example of in situ shale retorting: Fowler TD and Vinegar HJ: "Oil Shale ICP—Colorado Field Pilots," paper SPE 121164, presented at the SPE Western Regional Meeting, San Jose, California, USA, March 24–26, 2009.



^ Oil bank from MicroPilot injection. Taken after injection of an ASP solution, an FMI image (Track 3) clearly shows evidence of an oil bank and swept formation behind it: a circular bright area around a darker interior. A 3D cutaway (*right, top*) shows the modeled displacement as the ASP flood (dark blue) pushes an oil bank (green) away from the small drilled injection hole (white). A 2D vertical section (*right, bottom*) of conductivity, taken from an ECLIPSE model, matches the dimensions of the bank in the FMI image, with a swept area having a diameter of 28 cm [11 in.] and the outer range of the oil bank at 54 cm [21 in.] The water saturation after injection approaches 100%, both in the CMR-Plus log (Track 1) and the Dielectric Scanner log (Track 2).

Research has also progressed on accessing reservoirs for EOR injection. The US DOE funded development of microhole technology for boreholes ranging in diameter from 1¼ in. to 2⅜ in. and logging tools with ⅞-in. diameter. The objective is to drill such holes with coiled tubing and miniaturized BHAs to a depth of 6,000 ft [1,800 m]. Afterward, the program envisions injecting EOR chemicals into the formation and using miniaturized logging tools to evaluate the result.[59]

Recently, there has been increased activity in recovery of oil from tight formations such as the Niobrara, Bakken and Eagle Ford shales in the US. Although operators have only begun developing these unconventional oil plays, the lead time for developing EOR strategies for any play is long. Investigators have already begun looking at methods such as CO_2 flooding for additional recovery.[60]

Recovery from oil shales using in situ retorting might eventually be classed as an EOR method (see "Coaxing Oil from Shale," *page 4*). Oil shale is heated in situ to temperatures sufficient to convert the kerogen into oil and gas, and the products are produced through wellbores.[61] Several methods are undergoiong field test in the US.

EOR techniques run the gamut from laboratory successes not yet proved in the field to successful field applications that have recovered millions of barrels of additional oil over decades. As mature fields approach their economic limits for traditional recovery methods, the need for EOR applications continues to grow. Since most EOR methods have limitations on their applicability, the industry needs to broaden and deepen its expertise and prove applicability of more methods. The prize is significant: more oil produced from more known reservoirs. —MAA