Recent Developments and Remaining Challenges of Enhanced Oil Recovery

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There has been a renaissance in chemical EOR during the past few years because of major advances in the technology and high oil prices. Thermal and miscible gas methods are much more mature with the exception of processes such as co-injection of gases and surfactants for mobility control. The synergy between the EOR processes and improved reservoir characterization and formation evaluation, reservoir modeling and simulation, reservoir management, well technology, production methods, and facilities is significant and not as widely recognized as it should be.

Polymer flooding is the simplest and most widely used chemical EOR process. Polymer flooding has been used commercially since the 1960s; more oil is produced by polymer flooding than all of the other chemical EOR processes combined. Adding polymer to the water increases its viscosity. The benefit of polymer flooding increases as the oil viscosity and/or the reservoir heterogeneity increases. Polyacrylamide copolymers or hydrolyzed polyacrylamide (HPAM) polymers are by far the most widely used polymer for EOR. Much higher molecular weight HPAM is now available than when it was first used in the 1960s and 1970s. The quality of commercial HPAM polymer has also improved dramatically and the price relative to crude oil has decreased. In the early 1970s, oil sold for about USD 3/bbl and HPAM polymer for about USD 1.50/lb. Now oil is about USD 100/bbl and HPAM stays about the same price.

About 1 to 2 lbs of polymer are needed to produce an incremental barrel of oil, which means the polymer cost is about USD 1.50/bbl to USD 3/bbl. This helps explain why the number of polymer floods is increasing exponentially and about 1 billion lbs of polymer will be used for EOR this year. Most early polymer floods were done using very small amounts of polymer (i.e., low polymer concentrations and small pore volumes of polymer solution), but now we know polymer floods perform much better at large polymer concentration.

Incremental oil recovery is on the order of 12% original oil in place (OOIP) when polymer solution is injected for about one pore volume and values as high as 30% OOIP have been reported for some field projects. We have also learned that under some circumstances, HPAM polymer can reduce the so-called irreducible oil saturation below its water flood value and thus further increase oil recovery. Furthermore, low salinity brine can be used for the polymer solution with the...
potential of reducing the irreducible oil saturation even more as well as requiring a lower polymer concentration to provide the same viscosity.

It is not surprising that injecting one pore volume or more of polymer solution increases oil recovery and profit because decades of field experience show that profit is increased by continuing to inject carbon dioxide in miscible gas floods and steam in steam drives. The benefit of injecting polymer solution for long periods is often underestimated based on numerical simulations. Water fingers into the more viscous polymer solution when it displaces it. This process is difficult to simulate unless very small grid blocks are used.

It is a myth that HPAM cannot be used in high salinity brines, but it is true that more polymer is required to achieve a given viscosity as the salinity increases up to about 40,000 ppm total dissolved solids. No additional viscosity reduction occurs at still higher salinities. However, the choice of a suitable polymer also depends on the hardness of the brine and the temperature. Under anaerobic conditions, polyacrylamide is thermally stable up to at least 120°C, but it does hydrolyze at a significant rate above about 75°C depending on the pH and other variables. In soft brine, this is not a problem and, in fact, the viscosity increases with additional hydrolysis. The brine must be softened for alkaline surfactant polymer (ASP) flooding to use a conventional alkali such as sodium carbonate, so HPAM polymer can be used in ASP floods even at high temperature. However, above a certain level of hydrolysis and divalent cations (such as calcium), HPAM will precipitate. Commercial copolymers of acrylamide can be used under such conditions to extend the temperature limit in hard brines to about 100°C. More expensive copolymers of acrylamide or some more expensive bio-polymers are stable in hard brines up to at least 120°C. The best choice of polymer will depend on the brine's hardness, temperature, polymer cost, reservoir characteristics and other factors that need to be carefully studied and optimized to reduce risk and cost.

Low permeability is another technical limitation of polymer flooding. The lower limit of permeability depends on the molecular weight distribution of the polymer and the pore size distribution of the rock. Usually the limit is on the order of 5 md. A highly successful commercial full field polymer flood was done in a 5 md dolomite reservoir in the 1980s. In general, the economics become unfavorable at such low permeability because more polymer is needed to viscosify the water using low molecular weight polymers.

**Surfactant Polymer Flooding**

Unlike polymer floods, surfactant polymer (SP) flooding was not commercial when oil prices were low, but many technically successful SP pilots were done by 1986. Adding alkali to the surfactant solution (ASP flooding) reduced the cost significantly. Several small commercial ASP projects were reported in the 1990s. A much smaller amount of surfactant is needed for ASP flooding than for SP flooding. At current prices and under some reservoir conditions, the economics of ASP flooding appear to be very favorable since the chemical costs can be reduced to as little as USD 10/bbl of incremental oil produced. However, conventional ASP flooding is much more complex than SP flooding, requires oils that react with the alkali to form soap in-situ, and the injection brine must be softened. Incremental oil recoveries vary widely; when properly designed, it ranges between 20% and 30% OOIP following mature water floods.

There have been major advances in both SP and ASP EOR during the past five years. It is hard to overstate the potential impact of these technical advances. Some of the best surfactants now have a molecular weight 10 times larger than was previously used and the surfactant molecule is much more highly branched. These surfactants have low adsorption on both sandstones and carbonates in part because of the greater molecular branching. Though they cost about the same per pound as the old surfactants, they can be more than three times more efficient in terms of oil recovery per pound of surfactant. Surfactants that perform well in high salinity brines and at very high temperatures up to at least 120°C are available. Both SP and ASP floods can be used to recover oils with a viscosity up to at least 200 cp. If the surfactants are added to hot water, then the oil viscosity range can probably be extended to 10,000 cp or higher. Remarkably, the same high-performance anionic surfactants, such as alkyl ether sulfates developed for sandstone reservoirs, are also good choices for carbonate reservoirs. Furthermore, these surfactants are of higher purity and quality than those used previously and the inflation adjusted cost has gone down.

In addition to having better surfactants at a lower cost relative to crude oil, major advances have occurred in how to select the best surfactants, how to test them in the laboratory, and how to scale up laboratory data to the field. The primary goal of adding surfactants to water is to lower the interfacial tension (IFT) to about 0.001 mN/m. Essentially all of the oil trapped by capillary forces (residual oil) is displaced from the pores when the IFT is reduced to such ultra-low levels. It is of equal or greater importance that the surfactant solution form a microemulsion with
Reservoir simulation is needed to scale up the laboratory results to the field.

The next step in the laboratory testing program is to evaluate the SP or ASP solutions in reservoir cores. The phase behavior method is now so effective that the SP/ASP flood usually reduces the final oil saturation to less than 0.03 on the very first try. The most critical measurement of any core flood is the pressure drop across each section of the core. If the pressure gradient greatly exceeds the value possible in the oil reservoir, then the core flood data are not a good indication of reservoir performance and corrective measurements must be taken to improve the surfactant formulation.

Core floods must be done with a sufficiently long core and a sufficiently high residence time to be able to reliably scale them up by more than 100- to 1000-fold to reservoir well spacing by using a mechanistic reservoir simulator (Fig. 1).

We now have mechanistic chemical flood simulators that can be used to design SP/ASP flooding processes and predict performance. The improvements in simulation capability during the past few years have been continuous and highly significant. We also now have a better understanding of what is most important to measure and model. And we can do it much faster and more accurately than before. We can integrate the chemical flooding simulation process into the project workflow to ensure a more robust design. Decades of laboratory and field experience with SP flooding have shown that they are most robust when the formation salinity is higher than optimum salinity (lowest IFT) and the salinity in the polymer drive is lower than optimum salinity (called a salinity gradient) so that the surfactant goes through the optimum salinity even if the reservoir conditions (temperature, pressure, oil composition e.g., solution gas) are different than expected.

One of the biggest challenges of applying chemical flooding commercially is to focus on just a few critical issues, such as the salinity gradient, rather than on issues that make almost no difference with currently available high-performance surfactants and polymers. The most critical engineering design factor by far is the salinity of the injected polymer drive. ASP flooding is especially complex, but even so there are just a few design factors that dominate its performance.

Research into altering the wettability of a rock using surfactants has also been under way for decades. The main target is mixed wet or oil wet fractured carbonate reservoirs where most of the oil remains in the tight matrix. Cationic surfactants were used in most early research because of the positive charge on carbonate surfaces. Less expensive anionic surfactants have recently been found to perform as well or better than cationic surfactants.

The co-injection of gas with surfactant solutions (SG/ASG) is a new and rapidly evolving option that does not require the use of polymer and thus avoid some of the limitations of commercial polymers. Research on foams goes back several decades, but the differences now are so profound that it is probably better to use new names for the process rather than call it foam. The goal is not to make highly viscous foam for near well treatments. The goal of SG/ASG is to provide mobility control for an ultralow IFT surfactant solution by increasing the apparent viscosity by a factor similar to polymer viscosity so the pressure gradient will be low and the surfactant will transport long distances between wells. A low-quality foam seems to work best for this purpose. Remarkably, most if not all of the best surfactants for SP/ASP create enough foam in situ to reduce the mobility by the desired factor of about 10.

Surfactants can also be used with miscible gas flooding EOR such as carbon dioxide flooding. New CO₂ soluble surfactants have been developed that can be injected as a gas solution. There are several advantages to this approach. For example, if the surfactant is injected as an aqueous solution, then the water can segregate because of gravity or heterogeneity or both. Segregation reduces its effectiveness in controlling the mobility of the gas and thus decreases its effectiveness in improving sweep efficiency and oil recovery. We used the same fundamental scientific understanding of how to optimize surfactant molecular structure to make new surfactants for CO₂ that was developed by extensive research in the 1970s and 1980s for SP flooding. In fact, adding surfactant to CO₂ is likely to be the most common way to
Supplying chemicals for EOR offshore presents special challenges.

do CO₂ floods in the future. There may be a continuum between these different processes in the future.

Selection of EOR Process
How does an operator decide which EOR process to use and when? To provide a satisfactory answer requires an integrated study of the reservoir and its characteristics. In many cases, several of the EOR methods should be studied in depth before making a final decision rather than follow conventional wisdom or simplified screening criteria that may be out of date. The choice between carbon dioxide miscible flooding and one of the chemical flooding methods seems difficult in many cases.

A good starting point is to ask some very high-level questions:

• What is the current oil saturation?
• What is the oil viscosity? CO₂ flooding becomes very inefficient as the oil viscosity increases above about 10 cp unless surfactant is used to improve sweep efficiency. SP/ASP becomes less efficient above about 200 cp unless heat is used to reduce the oil viscosity. Polymer flooding has been used up to about 1000 cp. Above 1000 cp, conventional thermal EOR may be the best choice unless the reservoir is too deep or too thin and would cause excessive heat losses.

• What is the permeability and porosity and how heterogeneous is the reservoir? If the permeability is less than 5 md, then polymer, SP and ASP flooding become much less efficient compared with gas flooding processes such as CO₂ flooding and SG/ASG flooding. Of course the economics of EOR improve dramatically for all of the processes as permeability, porosity and thickness increase but to different degrees.

• Are sufficient volumes of CO₂ available or likely to be available at a reasonable cost in the future to flood the reservoir? Is the reservoir deep enough for the pressure to exceed the minimum miscibility pressure for CO₂?

• Is the reservoir naturally fractured and what are the characteristics of the fractures? Polymer flooding and surfactant imbition/wettability alteration processes can be used even in some highly fractured reservoirs.

After these questions are addressed, then what? The ideal strategy is to use both simplified models and detailed reservoir simulation models to explore the options assuming the process might be economic. If initial calculations indicate the process may be profitable, then there will be a need for additional laboratory and field measurements followed by more modeling. In many cases, a single well test will be justified to evaluate injectivity, reduction in oil saturation and other performance indicators that can only be assessed with field tests.

When comparing the economics of different processes, many factors must also be taken into account. The chemical methods have the advantage of lower capital cost than miscible gas and thermal methods, and commercial projects can start small and be expanded if successful without the need for expensive infrastructure such as a pipeline. On the other hand, there may be an incentive to sequester CO₂ oil reservoirs at some locations. Typically it takes about 10 Mcf of CO₂ to recover an incremental barrel of oil and about half of this gas will be left in the reservoir at the economic limit. The cost of the CO₂ will vary over a wide range depending on the location. Large volumes of inexpensive CO₂ are available in some places such as the Permian Basin in the US, whereas CO₂ that must be captured from a power plant will be very expensive.

So what are the most significant constraints on any kind of EOR? My guess is the following in order of importance: a shortage of experienced engineers and geoscientists with a fundamental understanding of EOR, uncertainty in oil prices, and risk aversion due in part to out-of-date knowledge and in part to the complexity of EOR compared with more conventional oil recovery. There are also environmental concerns that must be addressed for each process and location. For these and other reasons, it may take many years to ramp up EOR production to millions of barrels per day. The ultimate potential to increase total light and heavy oil production as both EOR technologies continue to improve is likely to be on the order of 1 trillion barrels assuming favorable economic and regulatory conditions exist over the next few decades, and the above constraints are fully understood and addressed. A much higher priority and much greater level of effort than currently being expended will be required over the long term to achieve that high potential. The technology is sound. The need is great. The potential is huge. Let’s get started.