A Realistic Look at Enhanced Oil Recovery

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The principal enhanced oil recovery (EOR) methods are outlined in a systematic and balanced manner and the current impact of these methods is assessed in the light of field experience. As such, this paper is a timely and comprehensive description of EOR methods and where they stand today and examines the reasons for the lack of success. The paper does not rely on voluminous statistics, nor does it give another set of screening criteria. Rather, it develops the process discussion in terms of mobility ratio and capillary number. It is shown that certain EOR methods, such as chemical floods, have inherent limitations explaining the lack of success in the field, in contrast to promising laboratory results.

INTRODUCTION

Enhanced oil recovery (EOR) is usually taken to mean oil recovery beyond primary production and waterflooding. In the case of very viscous oils and tar sands, with little or no primary and/or secondary productivity, EOR may even refer to the recovery techniques employed from the start. We are thus concerned with a whole range of unconventional–usually costly and complex–oil recovery methods, few of which have been shown to be commercially successful and then, too, only in specific reservoirs.

The interest in EOR, and particularly the field activity, rises and falls with the prospect of increasing or decreasing oil prices and also with the perceived foreign oil supply situation and government incentives. Thus, economics dominate much of the EOR activity reflected by the extensive field project surveys published by the *Oil & Gas Journal* every two years [1]. The large number of field projects for a given EOR method does not necessarily mean that the method is technically successful. Similarly, few field tests of a particular process do not imply that the process is technically ineffective. This simple-sounding statement has far reaching implications in the choice and application of a particular EOR method. As an example, Table 1 lists the number of projects and the oil production for several major EOR categories, based upon [1].

Quite a different reason for interest in the EOR methods is the simple fact that oil recovery by primary and secondary methods (pressure maintenance, waterflooding) is less than 30% of the oil in a reservoir and much less than that in many reservoirs. For the past fifty years, researchers have been consistently looking for methods to increase this figure. The volume of such research is again determined by the factors mentioned previously for field activity.

The objective of this article is to discuss the EOR methods from a mechanistic point

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Table 1. U.S. EOR production in 1992.

Recovery Method	Total No. of Projects	Oil Production B/D	Rate, m3/day
Thermal			
Steam	177	454,009	72,180
Combustion in situ	8	4,702	748
Hot water	6	1,980	315
Total thermal	**131**	**460,691**	**73,242**
Chemical			
Micellar-polymer	3	254	40
Polymer	23	1,940	308
Caustic/alkaline		0	0
Surfactant		0	0
Total chemical	**26**	**2,194**	**349**
Gases			
Hydrocarbon miscible/ immiscible	25	113,072	17,977
CO2 miscible	52	144,973	23,048
CO2 immiscible	2	95	15
Nitrogen miscible/ immiscible	7	22,580	3,590
Flue gas (miscible and immiscible)	2	11,000	1,749
Other	1	6,300	1,002
Total gas	**89**	**298,020**	**47,380**
Other			
Carbonated waterflood	0	0	0
Microbial	2	2	0.3
Total other	**2**	**2**	**0.3**
Grand total	**248**	**760,907**	**120,971**

of view. What are the technical limitations of each method as far as the oil recovery is concerned? Why do some of the recovery methods, which look so good in the laboratory, fail in the field? Oil recovery is not a good criterion for field applications where economics and cash flow (viz. oil production rate) are the key factors. Nevertheless, it is a worthwhile target to consider.

A useful and easy-to-read book on EOR is [2], written by recognized experts. Detailed process descriptions, selection criteria and field experience are summarized there. A more theoretical approach, especially for chemical

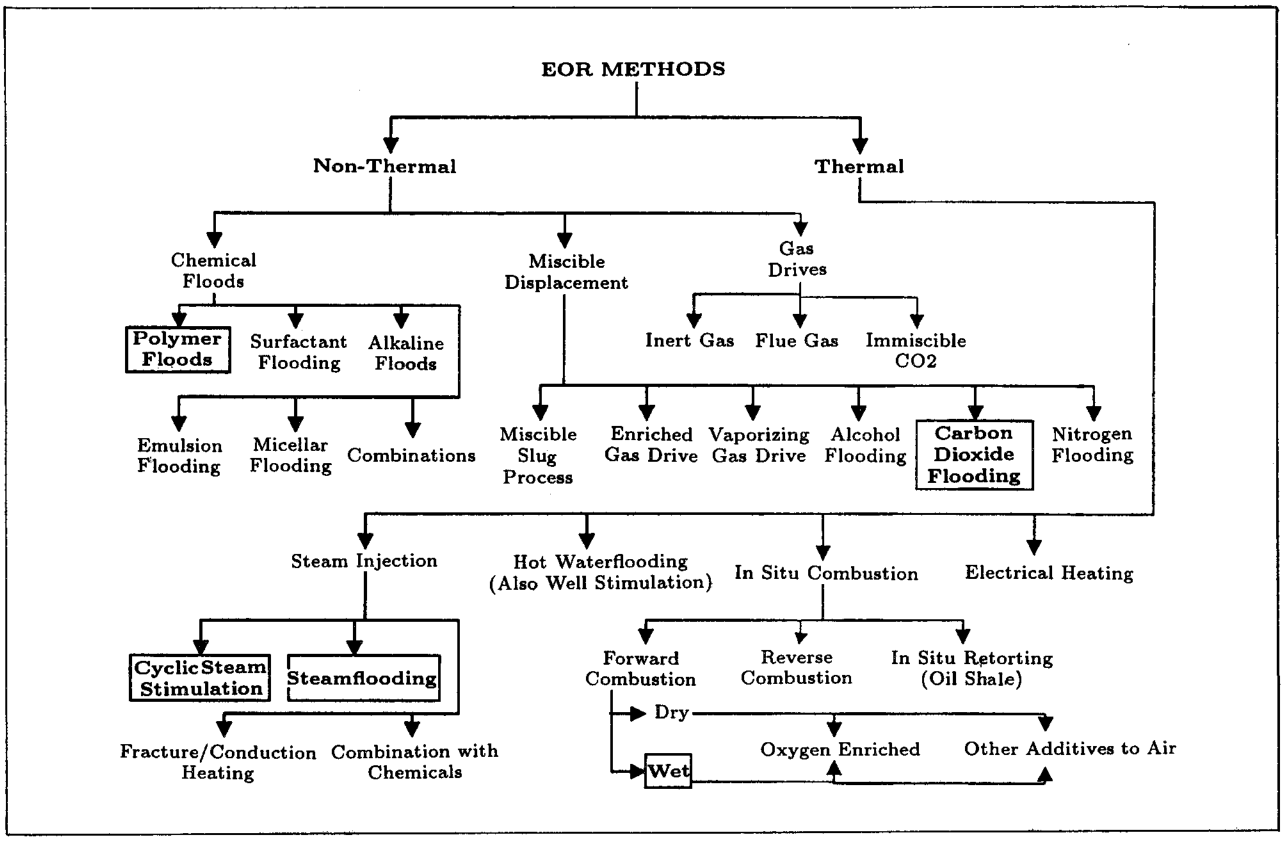

Figure 1. Classification of EOR methods. Commercial processes are highlighted.

methods, is offered by Lake's book [3]. For non-thermal methods, the series of articles by Mungan [4] is a useful reference.

EOR METHODS

Oil recovery methods can be broadly classified as non-thermal and thermal methods, depending on whether heat is employed in some form. In each case, a particular method may be applied to the wellbore itself, to the formation near the wellbore or to a large portion of the reservoir, such as a well pattern. Not all recovery methods offer these choices. Figure 1 shows a classification of EOR methods based on these ideas. While the EOR methods indicated in Figure 1 cover most of the possibilities, they are largely of academic interest. The more promising methods from the commercial point of view are highlighted.

Non-thermal EOR methods broadly consist of chemical and miscible processes. Chemical methods include polymer, surfactant, caustic and micellar/emulsion floods, and combinations thereof. More exotic field-tested chemicals include liquid ammonia, alcohols and a whole range of surfactants and alkalis. Even though chemical floods have had limited success in the field, they hold promise for the future.

Miscible methods include high pressure miscible drives using a hydrocarbon gas, nitrogen or carbon dioxide, as well as displacement by liquid hydrocarbons. Many variations are possible in the application of these processes, an important one being alternate injection of the miscible agent and water (WAG: water alternating gas).

Other methods which do not strictly fall into chemical or miscible categories include immiscible gas drives by carbon dioxide and inert gas.

Thermal methods broadly consist of steam injection (hot water can be taken to be zero quality [defined as the mass fraction of vapor in the liquid-vapor mixture] steam) and in situ heat generation, usually achieved by combustion of a portion of the oil, but also possible by other means, as shown in Figure 1. Many variations of steam injection and in situ combustion have been tested. Of the other methods, use of electricity has received some attention.

PRINCIPLES OF EOR

A given EOR method can have one or more of several goals, which are as follows.

Improvement of the Mobility Ratio

Mobility ratio, M, is usually defined as the mobility λ_{ing} ($= k/\mu$, where k is effective permeability and μ is viscosity) of the displacing fluid divided by the mobility λ_{ed} of the displaced fluid (assumed to be oil in this discussion). If $M > 1$, clearly the displacing fluid, e.g., water in a waterflood, moves more easily than the displaced liquid, i.e., oil. This is not desirable, because the displacing fluid will flow past much of the displaced fluid, displacing it inefficiently. Thus, the mobility ratio determines displacement efficiency, i.e., the (microscopic) efficiency of oil displacement within the pores. For values of M much larger than 1, the displacing fluid will channel past oil ganglia. This is often called viscous fingering. For maximum displacement efficiency, M should be ≤ 1, usually denoted as favourable mobility ratio. If $M > 1$ (unfavorable), then, in the absence of viscous fingering, it merely means that more fluid will have to be injected to attain a given residual oil saturation in the pores. As an example, for the simple case of a waterflood, oil recovery is plotted in Figure 2 as a function of mobility ratio, for fixed volumes of the injected fluid. Plots like this can be prepared using the Buckley–Leverett theory.

Like displacement efficiency, areal sweep efficiency as well as conformance (or vertical sweep efficiency) decrease as the mobility ratio increases. In other words, if the displacing fluid flows more readily than oil, the displacement is inefficient also on a macroscopic basis.

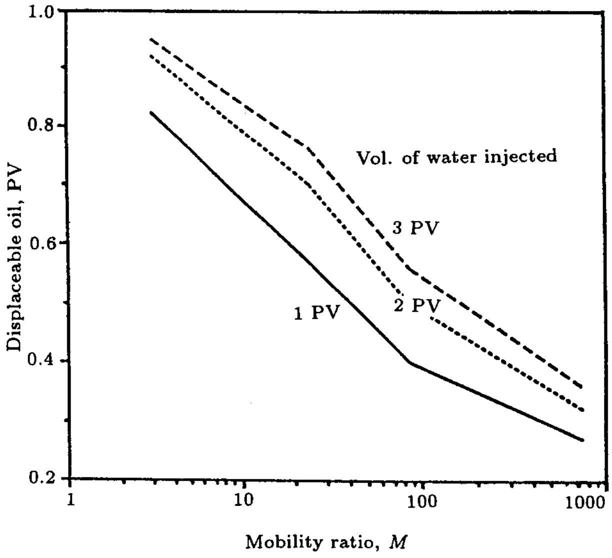

Figure 2. Effect of mobility ratio on waterflood oil recovery.

Definition of M becomes rather involved and arbitrary in the case of EOR methods more complex than a waterflood, but the basic concepts are still valid. Notice that even in the case of a waterflood, there are three ways of defining M, depending on how the displacing phase permeability is defined.

Mobility ratio M can be made smaller, i.e., improved, by lowering the viscosity of oil, increasing the viscosity of the displacing fluid, increasing the effective permeability to oil and decreasing the effective permeability to the displacing fluid. (It is often more convenient to talk in terms of mobilities). The various EOR methods aim at one or more of these effects.

Increasing the Capillary Number

The capillary number, N_c, is defined as $\mu v/\sigma$, which is the same as $k\Delta p/\sigma L$,where μ is the displacing fluid viscosity, v is Darcy velocity, σ is interfacial tension (IFT) between the displaced and the displacing fluids, k is effective permeability to the displaced fluid, and $\Delta p/L$ is pressure gradient. Taber [5] pointed out the implications of lowering the residual oil saturation, which is a function of the capillary number. Since then, other authors have given correlations of the two. Figure 3 shows plots of the remaining oil saturation versus N_c on the basis of data published by various authors [6]. It is clear that the capillary number can be increased, and thereby the residual oil saturation decreased, by reducing oil viscosity or increasing pressure gradient, but, more than anything, by decreasing the IFT.

In an earlier work, Reed [7] reported that residual oil saturation showed a significant decrease only when very low IFT's of the order of 10^{-2} mN/m were employed. Taber also noted that a critical value of $\Delta p/\sigma L$ had to be exceeded to effect a reduction in the residual oil saturation, concluding that the IFT would have to be lowered by a factor of about 1000 to make a significant gain in oil recovery. This is feasible under laboratory conditions, but extremely difficult under field conditions. Notice also that if IFT is zero, the capillary number becomes infinite and the interface between the displacing and the displaced fluids disappears. In other words, oil is displaced miscibly. Under these conditions, the oil displacement efficiency is 100% in those pores where the displacing fluid contacts oil.

RECOVERY METHODS

It was seen above that oil recovery is strongly dominated by the mobility ratio and the capillary number. A change in σ would affect capillary pressure, hence effective permeabilities, and finally, both M and N_c. In reality, the situation is far more complex because emulsions, rock-fluid interactions and other factors difficult to quantify (flow of fines, temperature effects, compaction, etc.) are involved in most EOR processes. Also, wettability plays an important role.

We shall now discuss the more practical EOR methods, with comments regarding their applicability. It is worth noting that many screening guides have been published, which help in selecting an EOR method for a given reservoir. While such guides serve a purpose, they should be used with caution. Formation geology and mineralogy are the more important factors in determining success in the field. Apart from that, past experience is an important ingredient in EOR project design.

POLYMER FLOODING

In this process, a very small amount (200 to 1000 mg/l, or ppm) of a high molecular weight (2 to 5 million) water-soluble polyacrylamide or polysaccharide (biopolymer) is added to the water in a waterflood-type operation. The process is deceptively simple. The choice of the polymer and the concentration to be used are the crucial steps in design. A bewildering array of polymers is available. Careful laboratory tests are needed. Even after that, the laboratory results must be related to the field.

The goal in polymer flooding is to lower the mobility of the flood water. This is the result of an increase in the apparent viscosity of water and a permanent decrease in the relative permeability to water. Polymer does not lower the residual oil saturation, but it does increase oil recovery as a result of improved sweep, being a function of mobility ratio. The long polymer chains can decrease the mobility of water by a factor (resistance factor) of 10 or more, much more than a polymer solution viscosity measurement would indicate. The overall result is a reduction in the mobility ratio, which leads to an increase in oil recovery.

Many complicating factors affect oil recovery by polymers. Polymer degradation due to high salinity interstitial water, temperature, aging of the polymer, polymer gel formation, high shear rates, etc., are important factors. The point in the life of a waterflood at which polymer injection is initiated is important also (earlier is better).

Polymer flooding has provided incremental oil recoveries of the order of 5% on the average. There have been many failures due to improper design. Even though laboratory tests cannot be scaled up to field, such tests are useful for screening various types of polymers for a given reservoir.

Polymers show pseudoplastic, i.e., shear-thinning behavior. The presence of electrolytes (salts) and divalent cations (calcium and magnesium), more so than monovalent cations (sodium), in the formation waters also leads to a reduction in the effective viscosity of polymer solutions. This is partly because the long chains coil up, so that the molecules assume a nearly spherical shape. Polysaccharides are more resistant in this regard, but require careful filtering and the addition of bactericides such as formaldehyde (20–100 ppm). Wellbore plugging may occur due to cellular debris or crosslinking of molecules. Very few field projects have utilized biopolymers such as xanthan gum. An oxygen scavenger, such as sodium hydrosulfite, may be added to a polymer solution. It may have the opposite effect if free oxygen is present.

Loss of polymer to formation can occur by adsorption and mechanical entrapment. Laboratory tests tend to give higher values of adsorption than those observed in the field. Adsorption tends to increase with salinity, high clay content and lack of consolidation. Polymer floods have been more successful for moderately viscous oils, in the range of 5 to 200 mPa.s. Reservoir permeability should be higher than 20 md, and temperature should not be higher than 80° C. If a gas cap or a bottom water zone is present, polymer channelling would occur. Polymer may be ineffective in a mature waterflood, in view of the low mobile oil saturation.

As seen above, careful laboratory and geological screening is necessary to ensure success. The principal advantage of polymers, is the ability to improve vertical flood profile, or conformance, because the injected polymer will tend to increase the resistance to flow of water in the swept zones, leading to increased water flow in the less swept layers. Another important role of the polymers is as driving agents for mobility control, as in micellar flooding. On

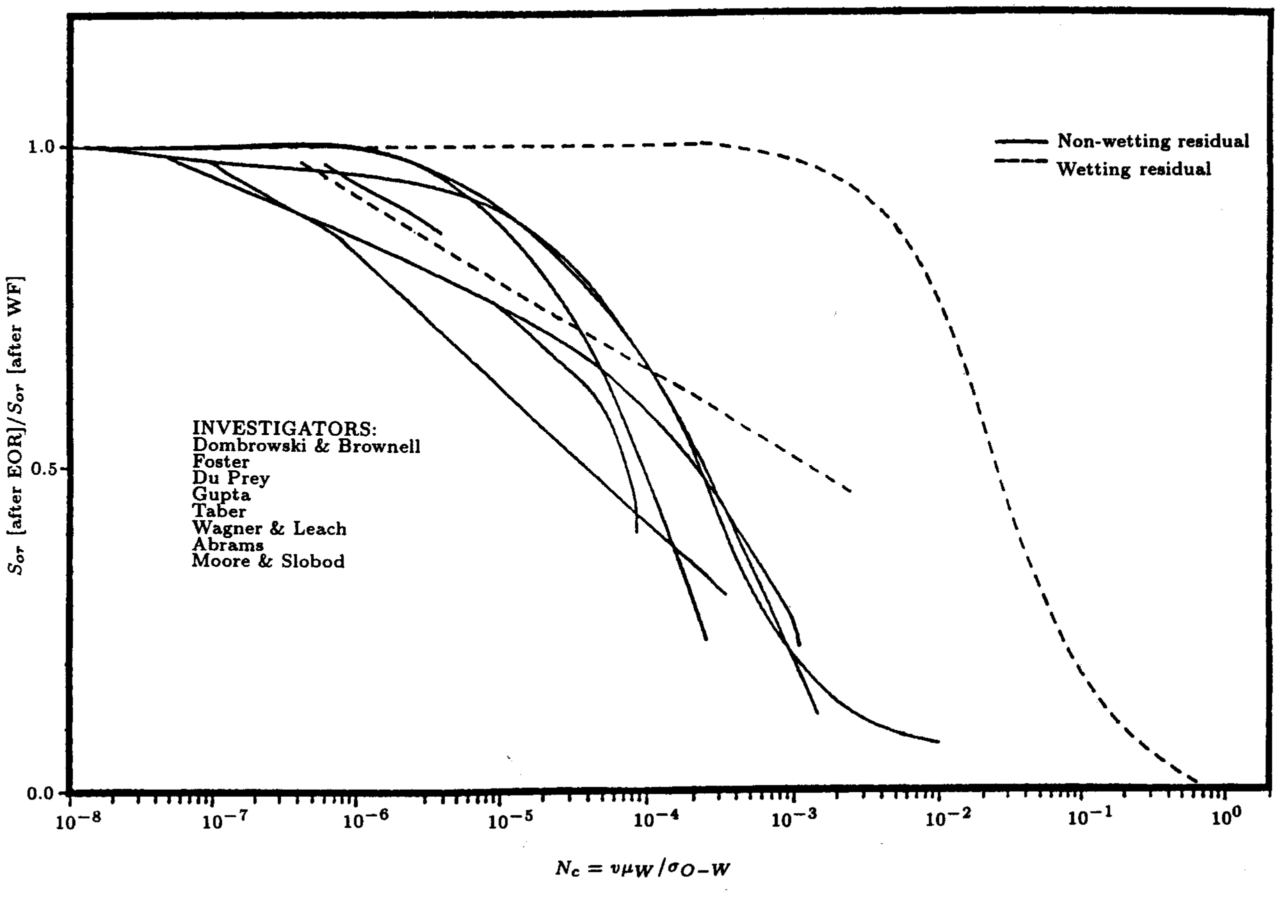

Figure 3. Residual oil saturation as a function of a capillary number [6].

the whole, polymer flooding has a good chance of success in moderately viscous oils, if the expected low incremental recovery is economical.

MISCIBLE DISPLACEMENT

Miscible displacement, or solvent flooding, consists of injecting a displacing agent such as a solvent that is completely miscible with the in-place oil. As a result, the IFT between the two is reduced to zero (i.e., there is no longer an interface), the capillary number is infinite and 100% oil displacement by the injected solvent is assured in the pores swept by the solvent if the mobility ratio is favorable (solvent more viscous than oil). Under ideal conditions, the displacing fluid and oil mix over a narrow band (called mixing zone or transition zone), which displaces all of the oil ahead like a piston.

The displacing fluid may be a hydrocarbon solvent such as propane or a high pressure gas which achieves miscibility after several contacts with the in-place oil. It may even be an alcohol that is miscible with both oil and water, thus, achieving true "piston-like" displacement of both oil and water. Carbon dioxide and nitrogen can serve as miscible displacement agents under the right conditions (very high operating pressure, high API gravity crude). Micellar solutions, or microemulsions, may act as "miscible type" fluids in that the oil is not displaced completely. The same is true for certain alcohols.

Miscible displacement can be a first contact type such as that of a hydrocarbon by another, the two being miscible in all proportions. Displacement of a light oil by propane or LPG may fall into this category. On the other hand, displacement of an oil by a high pressure gas is usually of the multiple contact type, i.e., miscibility between the two is achieved after several contacts and the accompanying phase equilibria. A ternary phase equilibrium diagram is used to determine if, and after how many contacts, miscibility would be achieved at the operating pressure. The different types of miscible processes are as follows.

Miscible Slug Process

In this case, a propane or LPG slug (about 5% hydrocarbon pore volume; HCPV) is used and is driven by lean gas, e.g., natural gas or methane; flue gas has also been used. Often water is injected with the drive gas in small alternating slugs. This has the effect of improving the mobility ratio at the gas-slug interface; the less viscous lean gas, in effect, acts as a viscous fluid. This approach is used in other miscible processes as well. The slug will be a liquid if the reservoir temperature is below the critical temperature (97° C in the case of propane). The pressure should be such that there is miscibility at the front edge of the slug and the in-place oil as well as between the trailing edge and the driving gas, otherwise miscible displacement will not be achieved. This latter requirement would govern the operating pressure, being 7 to 9 MPa. It is clear that if the formation is not deep enough (over 500 m), fracturing would occur.

Enriched Gas or Condensing Gas Drive

In this case, a slug (10–20% HCPV) of gas enriched with ethane to hexane fractions (propane-methane mixture, separator gas) is used, driven by lean gas and water in the WAG mode. These fractions are largely transferred to the oil near the injection point, while lean gas moves on. Eventually, a miscible zone is formed between the injected gas and the reservoir oil and displaces the oil ahead. The operating pressure for this process would be higher than that for a propane slug, being in the range of 10 to 20 MPa.

Vaporizing Gas Drive

This is a multiple contact process, employing lean gas (methane). In this case, the ethane to hexane fractions are transferred from the oil to the gas until miscibility is achieved. The operating pressure in this case is higher, above 20 MPa. Flue gas or nitrogen may be substituted for lean gas, with an increase in pressure requirements to about 30 MPa. The process pressure, point of miscibility and other parameters can be determined precisely.

Overall Assessment

The above miscible displacement processes should be used for 35°–45° API oils, with viscosities of 5–10 MPa.s. Formation permeability should be low, 50 md or less, and thickness small. This is to minimize the gravity segregation of the injected gas and oil. A problem inherent in all miscible processes is that of viscous fingering of the less viscous material, causing slug dissipation in one way or another. Updip injection and downdip production would tend to reduce these problems.

Hundreds of miscible floods have been conducted but very few have been successful because of the problems noted above. Other problems are related to geology (reservoir heterogeneity) and the availability of suitable materials. Miscible displacement has been very successful in reef-type reservoirs in Alberta with downward displacement of oil. Such gravity stabilized drives can recover as much as 90% of the in-place oil [8].

CARBON DIOXIDE FLOODING

Carbon dioxide in the liquid state (critical temperature is 31.0° C, pressure 7.40 MPa) is a rather unique oil recovery agent. Because of the low critical temperature, it is usually in a gaseous state when used for oil recovery. Miscible displacement by carbon dioxide is similar to that in a vaporizing gas drive, but in this case a wider range of fractions, viz. ethane to C_{30}, are extracted. As a result, the carbon dioxide flood process is applicable to a wider range of reservoirs at lower miscibility pressures than those for the vaporizing gas drive. The minimum miscibility pressure (MMP) is usually determined by a slim tube test [2]. Correlations such as those of Holm and Josendal [9] are also useful for estimating the MMP.

Carbon dioxide lowers oil viscosity (an effect that is important in heavy oils) and causes swelling of the oil, but the principal mechanism in the case of light oils is miscible displacement. Many injection schemes have been proposed for the carbon dioxide process. Unless the reservoir permeability to water is too low, a desirable scheme would consist of the injection of about 5% HCPV slug, followed by water and carbon dioxide injection in the WAG mode, until about 20% carbon dioxide has been injected.

Carbon dioxide flooding should be used in moderately-light to light oil reservoirs (API gravity $>$ 25°), deep enough to contain the MMP. If available, it may be a better choice than other miscible methods in view of its higher viscosity and greater density than methane, for example. It should be noted that carbon dioxide is soluble in water, thus leading to some loss, and acid solutions can cause severe corrosion problems.

Nearly 50 carbon dioxide floods have been carried out. Some of these have been economic successes. The status of many floods is still unclear. It can be said that the process is inherently attractive, but requires careful engineering.

MICELLAR FLOODING

Micellar or microemulsion flooding is a complex but very promising tertiary oil recovery method for light oils. It has been extensively tested in the laboratory and many successful field tests have been conducted. A recent review was given by Thomas and Farouq Ali [10].

Micellar flooding consists of the injection of a micellar solution slug (about 5% PV), followed by a polymer solution slug (buffer, of the order of 50% PV) which is driven by flood water. Often a preflush is injected ahead of the micellar buffer to condition the rock. The micellar solution used is the key element in the process. It consists of water, a suitable hydrocarbon and 10–15% surfactants, together with smaller quantities of a salt and a suitable alcohol. The latter afford the possibility of viscosity and phase behavior control. The micellar solution thus prepared is tested for phase interactions with the reservoir oil and brine, and also in core floods. Under optimal conditions, a micellar solution (less mobile than the in-place oil and water) would displace oil and water in a miscible manner in that the displacement is akin to that by a mutually soluble alcohol, only more efficient. The polymer buffer, less mobile than the slug to delay the dilution of the slug by the drive water, is an important part of the process.

Micellar flood design requires a great deal of background work, but once a proper slug-buffer system is designed, the process can be very efficient. One of the performance indices is the oil recovery-to-slug ratio. In the field, these have exceeded values of 3.0. Micellar flooding would normally be considered for a light oil (viscosity less than 20 mPa.s), which has been previously waterflooded (low salinity). The reservoir pressure is not critical, based upon the authors' work, but temperature should not be too high to cause micellar/polymer degradation. The main impediment in developing a micellar flood could be cost of materials and wells, because small well spacings are employed. As a result, the micellar flooding process has been successful in depleted, shallow reservoirs of Pennsylvania and Illinois, where the crudes are generally high-priced and the materials are relatively less costly. The micellar flooding process is the only recovery method that has been shown to be effective for recovering oil from watered-out light oil reservoirs.

STEAM INJECTION

Table 1 shows that 60% of all EOR oil production in the USA is by steam injection. In Canada, while there are several successful miscible floods, steam injection accounts for nearly all production from tar sands. Unlike the non-thermal methods discussed previously, thermal methods involving steam/hot water injection or in situ combustion are primarily intended for heavy oils and tar sands (10°–20° API). On the other hand, steamflooding has been successful in a number of light oil reservoirs; in situ combustion seems to work best for moderately heavy oils.

Cyclic Steam Stimulation

This is the most successful EOR method and is usually the first stage in steamflood development. In Canada, it is the only successful recovery method at present for tar sands.

Cyclic steam stimulation (CSS) is basically a single well operation, although sooner (if fracturing occurs) or later, communication between the wells develops and the process becomes very complex. Steam is injected into a well at a high rate (200 m^3/day water equivalent in Cold Lake) for a short time (one month), following which the well may be shut in for a few days for heat distribution. After that, the well is allowed to flow, and later pumped. The oil rate increases rapidly to a high value, and stays at an economic level for a long period (10 m^3/day average over six months). When the rate becomes uneconomic, or if the oil is too cold (i.e., viscous) to be pumped, the whole process is repeated. As many cycles are conducted as are economic or advisable, if a steamflood is to be conducted afterwards.

In principle, the mechanism of CSS is simple: the injected steam largely bypasses the oil around the wellbore, heating it in the process. When the well is put on production, the mobilized oil flows into the wellbore, driven by reservoir pressure, gravity, compaction or other forces. In Cold Lake, steam injection is usually effected under fracture pressures and the process is much more complex, with interwell communication coming into play early. It is clear that in CSS and other thermal methods, the intent is to improve the mobility ratio M by greatly reducing oil viscosity.

Cyclic steam stimulation is likely to be successful in highly viscous oils with a good reservoir drive. Generally, the performance (e.g., oil-steam ratio, OSR, being m^3 oil produced per m^3 of steam injected) declines as more and more cycles are carried out. This may not be so if fracturing occurs. Oil recovery is usually small, since only a small portion of the formation is affected. In Cold Lake, it is about 20% for the smaller well spacings (< 2 ha/well). Formation thicknesses in excess of 10 m, and depths less than 1000 m are desirable, but exceptions may be made. Near-wellbore geology is extremely important in CSS. Bottom water and gas cap are undesirable but redeeming features may be present.

Steamflooding

Steamflooding, much like waterflooding, is a pattern drive, with arrays of injection and production wells. In this case, the performance is strongly dependent on the pattern size, since heat loss to the surrounding rocks can consume a large proportion of the injected heat. Steam is continuously injected into the injector, resulting in the formation of a steam zone, which advances at an ever-decreasing rate. Steam override due to gravity can be a problem. Steam reduces the oil saturation within the steam zone to very low values, of the order of 10%. Oil is transported by steam distillation also, which is the main mechanism in steamflooding light oils.

When steam breakthrough occurs, the steam injection rate is reduced to a value that is enough to supply the heat loss. Other measures may include shutting off steam producing intervals, recompletion of wells and even drilling of infill producers. At a later time (upon the injection of about half-a-million KJ/m^3 of rock), steam is discontinued and either hot water is injected or the injectors are shut in while the producers are kept on. There are also other options for operating mature steamfloods.

Steamflooding is feasible if the in-place oil has sufficient mobility–the oil viscosity should be less than 1000 mPa.s and the oil permeability should be of the order of a Darcy. Formation thickness should be at least 10 m, and depth less than 1000 m. It should be noted that the most successful steamfloods are in California and Indonesia, at much smaller depths and in much thicker formations. Formation pressure should be low to permit steam injection at a relative low pressure. Low operating pressures are desirable for many reasons. Formation geology plays an important role in steamflooding. Bottom water and gas cap may be undesirable. There are examples (e.g., Peace River), where a limited high water zone was used to advantage for heating the formation. Steam front advance can take many forms depending on the reservoir conditions.

The oil recovery in a steamflood can be high (over 50% in many cases) but the oil-steam ratio is lower than that in cyclic steam stimulation because of the higher heat loss.

IN SITU COMBUSTION

In situ combustion, or fireflooding, is a unique process because a portion (about 10%) of the in-place oil is oxidized to generate heat. As such, the process has a high thermal efficiency. Air (or oxygen-enriched air, or even pure oxygen) must be injected to oxidize the oil. As a result, large volumes of flue gas are produced causing mechanical problems such as low pump efficiency, abrasion and erosion as well as reservoir oil flow restriction due to high gas saturation.

As far as the combustion process is concerned, heat is generated within a very narrow combustion zone at a high temperature (around 600° C). Directly ahead of the combustion zone, cracking of the oil occurs, leading to deposition of a heavy fraction (coke) which burns to support combustion. The combustion zone effectively acts as a piston and must burn or displace everything ahead of it before it can advance.

It is clear that the oil near the producers is at the original temperature for a long time and thus it must be mobile enough to be produced. There is usually severe gravity override of the combustion zone and, as a result, it is more nearly horizontal than vertical. Once breakthrough occurs in a producer, well temperatures increase steeply and operation becomes difficult and costly. At the same time, however, the oil viscosity is greatly lowered so the oil production rates are also at a peak. Cooling of the producers may be needed.

Corrosion, a problem in in situ combustion, becomes ever more severe. When oxygen enrichment is used, premature oxygen breakthrough is a common problem. An important advance in in situ combustion is water injection with air (wet combustion). Water helps to transport the heat accumulated in the burned sand downstream and thus increases the thermal efficiency of the process.

Well over one hundred firefloods have been conducted with relatively few clear successes. Oil recovery has averaged 50% and the air-oil ratio (AOR, defined as sm^3 of air needed to produce one sm^3 of oil) has ranged from 1000 to 3000, the lower values being typical of wet combustion.

OTHER RECOVERY METHODS

Apart from the above, many other oil recovery methods have been proposed. Notable among these are surfactant flooding and alkaline flooding and their many variations, in particular the combinations with polymer flooding.

Some of the earliest research was conducted on surfactant flooding, the intent being to lower the oil-water IFT, increase the capillary number and lower the residual oil saturation. Over the years, many advances have been made, notably the use of petroleum sulfonates as surfactants. These are more effective than conventional surfactants and less susceptible to adsorption on the rock surface and interactions with minerals–the Achilles heel of all chemical flooding processes. Many surfactant floods have been carried out using both high and low concentration slugs and using polymer as the drive fluid in many cases. On the whole, success in the field has been limited and many problems remain to be solved before this type of chemical flood can be commercially successful.

Another important category of chemical flooding methods is alkaline flooding. In this case, a suitable alkali (usually sodium hydroxide or caustic) is injected in a dilute aqueous solution which reacts with the acid compounds in the crude oil to form surfactants in situ. These surfactants lead to a reduction in IFT and, also, the emulsions formed as a result help in improving the mobility ratio in a number of ways. A concise discussion of the process has been given by Johnson [11].

One of the problems with alkaline flooding is the consumption of the chemical (caustic) by the rock, occuring due to a number of mechanisms, including clay reactions. Furthermore, IFT studies using caustic show that considerable concentrations (often approaching 1%) are necessary in order to effect a significant reduction in the IFT. Combinations with polymer flooding and surfactant have also been tested. In caustic flooding, as the chemical must react with the oil, its flow pattern is important. Also to be considered is the dilution of the injected solution by the formation water, as well as the effect of salts on IFT. Caustic floods have had limited success in the field. Such a flood should be considered for a given crude oil, if the acid number is 0.5 mg KOH/g crude, or greater. Heavy oils appear to be better suited for this process.

Many non-thermal oil recovery methods have been tested for heavy oil recovery. An extensive review of these was recently given by Selby, Alikhan and Farouq Ali [12]. Few field tests have been successful for the reasons noted there. Immiscible carbon dioxide flooding seems to hold promise for moderately heavy oils.

SUMMARY AND CONCLUSIONS

Numerous EOR methods have been proposed and several of these have been discussed in detail. Hundreds of field tests have been conducted, but relatively few have been economic successes. Many EOR methods, particularly chemical floods, look good in the laboratory but fail in the field. This is due to the inability to carry out scaled experiments in this and other instances. Numerical simulators of many of these processes are still in the early stages of development, partly because the process mechanisms are not fully understood.

Much can be learned from economic and/or technical field failures, but most of these are not publicized. Screening criteria can provide some guidance in process selection, but remember that if field success is the objective, the choice is very narrow indeed. Apart from that, formation geology and mineralogy can render other criteria meaningless. In EOR, there is no substitute for experience. Try to interpret the process mechanism in terms of the mobility ratio and capillary number.

Looking at the EOR methods which have been commercially successful, it can be said that steam injection has a high chance of success, miscible displacement may be successful under special conditions and carbon dioxide (miscible) flooding is still somewhat of a question mark, although it has potential. In situ combustion has lost much of its past appeal, but wet combustion may work where steam is not applicable. The same is true for the immiscible carbon dioxide process. Micellar flooding has been proven in the field, but remains a complex, high cost process. Of the remaining chemical methods, polymer flooding may yield modest incremental oil. Alkaline and surfactant floods have great research potential but are high risk field processes. All EOR methods are low margin operations under the best circumstances.

Considering that over two-thirds of the oil remains unrecovered in fully developed oil reservoirs, research on potentially useful EOR methods as well as field testing are very worthwhile long-term activities.

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