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## EOR'S MISCIBLE FLOODING OVERVIEW

**Background.** Global energy demand in 2050 could double from its 2016 level, assuming the emerging economies follow established growth patterns. The contribution to supply made by renewable forms of energy is growing steadily and could reach 30% by 2050. This, however, leaves a huge balance to be met, so oil and gas will remain an indispensable part of the global energy mix for decades.

At the same time, existing oil fields are maturing and the task of finding and recovering new reserves becomes more challenging. Consequently, providing these much needed hydrocarbons poses a challenge that requires effective and innovative responses.

Mature fields worldwide account for a large proportion of the global oil supply. Therefore effective strategies to maximize the amount of oil we can recover from them are vital to future supply. Operating companies are continually searching for innovative ways of finding, developing and producing hydrocarbons that are efficient and cost-effective and minimize harm to the environment.

The primary objective in a miscible process is to displace oil with a fluid that is miscible with the oil (i.e., forms a single phase when mixed at a proportions with the oil) at the conditions existing at the interface between the injected field and the oil bank being displaced. The miscible process requirements are characterized by a low-viscosity crude oil and a thin reservoir. A low-viscosity oil will usually contain enough of the intermediate-range components for the multicontact miscible process to be established. The requirement of a thin reservoir reduces the possibility that gravity override will occur and yields a more even sweep efficiency [1, 2].

**Overview.** The microscopic displacement efficiency is a measure of how well the displacing fluid mobilizes the residual oil once the fluid has come in contact with the

oil. The mobilization of the residual oil saturation in a water-wet system requires that the discontinuous globules be connected to form a flow channel. In an oil-wet porous medium, the film of oil around the sand grains needs to be displaced to large pore channels and be connected in a continuous phase before it can be mobilized. The mobilization of oil is governed by the viscous forces (pressure gradients) and the interfacial tension forces that exist in the sand grain–oil–water system.

There have been several investigations of the effects of viscous forces and interfacial tension forces on the trapping and mobilization of residual oil. From these studies correlations between a dimensionless parameter called the capillary number  $N_{vc}$  and the fraction of oil recovered have been developed. The capillary number is the ratio of viscous forces to interfacial tension forces and is defined by Eq. (1) [3]:

$$N_{vc} = \frac{V\mu_w}{\gamma_{ow}} = \frac{K_0 \Delta P}{\phi \gamma_{ow} L} \quad (1)$$

where  $V$  is the Darcy velocity,  $\mu_w$  the viscosity of displacing fluid,  $\gamma_{ow}$  the interfacial tension between displaced and displacing fluid,  $K_0$  the effective permeability to displaced phase,  $\phi$  the porosity, and  $\Delta P/L$  the pressure drop associated with Darcy velocity.

Fig. 1 is a schematic representation of the capillary number correlation. The correlation suggests that a capillary number greater than  $10^{-5}$  is necessary for the mobilization of unconnected oil droplets. The capillary number increases as the viscous forces increase or as the interfacial tension forces decrease.

**The main aim.** It is considered that the microscopic displacement efficiency is largely a function of interfacial forces acting between the oil, rock, and displacing fluid. If the interfacial tension between the trapped oil and the displacing fluid could be lowered to  $10^{-2}$  to  $10^{-3}$  dyn/cm, the oil droplets could be

deformed and could squeeze through the pore constrictions.

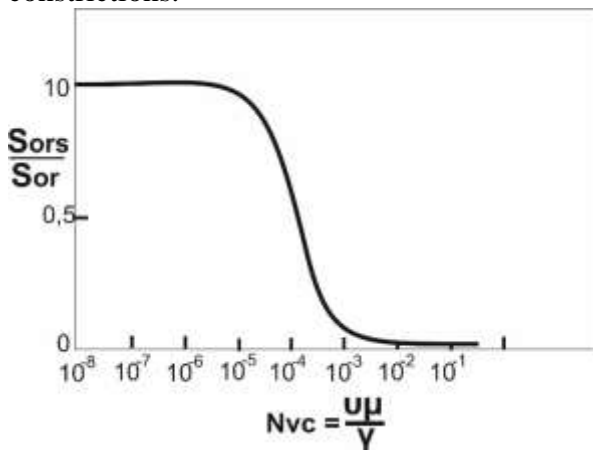


Fig. 1. Capillary number correlation

A miscible process is one in which the interfacial tension is zero; that is, the displacing fluid and the residual oil mix to form one phase. If the interfacial tension is zero, then the capillary number  $N_{vc}$  becomes infinite and the microscopic displacement efficiency is maximized.

**Project concept.** There are two major variations in the process. In one, called a single-contact-miscible (SCM) process, the injected fluid is directly miscible with the reservoir oil at the conditions of pressure and temperature existing in the reservoir. Fig. 2 is a schematic of a miscible process [4].

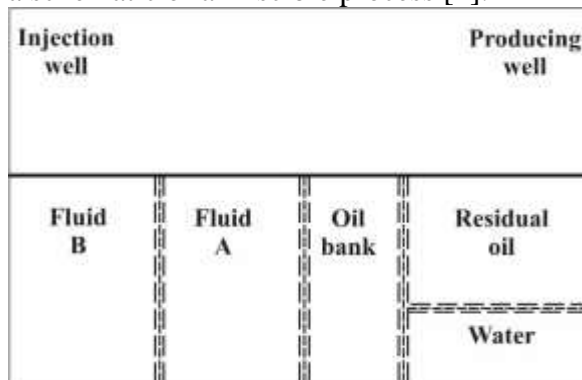


Fig. 2. Schematic of an enhanced oil recovery process requiring the injection of two fluids

Fluid A is injected into the formation and mixes with the crude oil, which forms an oil bank. A mixing zone develops between fluid A and the oil bank and will grow due to dispersion. Fluid A is followed by fluid B, which is miscible with fluid A but not generally miscible with the oil and which is much

cheaper than fluid A. A mixing zone will also be created at the fluid A–fluid B interface. It is important that the amount of fluid A that is injected be large enough that the two mixing zones do not come in contact. If the front of the fluid A–fluid B mixing zone reaches the rear of the fluid A–oil mixing zone, viscous fingering of fluid B through the oil could occur. Nevertheless, the volume of fluid A must be kept small to avoid large injected-chemical costs.

Consider a miscible process with *n*-decane as the residual oil, propane as fluid A, and methane as fluid B. The system pressure and temperature are 140 bar absolute (bara) and 40°C, respectively. At these conditions both the *n*-decane and the propane exist as liquids and are therefore miscible in all proportions. The system temperature and pressure indicate that any mixture of methane and propane would be in the gas state; therefore, the methane and propane would be miscible in all proportions. However, the methane and *n*-decane would not be miscible for similar reasons. If the pressure were reduced to 70 bara and the temperature held constant, the propane and *n*-decane would again be miscible. However, mixtures of methane and propane could be located in a two-phase region and would not lend themselves to a miscible displacement. Note that in this example the propane appears to act as a liquid when it is in the presence of *n*-decane and as a gas when it is in contact with methane. It is this unique capacity of propane and other intermediate gases that leads to the miscible process.

The single-contact miscible process involves such injection fluids as liquefied petroleum gases (LPGs) and alcohols. The injected fluids are miscible with residual oil immediately on contact. The second type is the multiple-contact, or dynamic, miscible process. The injected fluids in this case are usually methane, inert fluids, or an enriched methane gas supplemented with a C2–C6 fraction. The injected fluid and oil are usually not miscible on first contact but rely on a process of chemical exchange between phases to achieve miscibility.

The oil–LPG–dry gas system will be used to illustrate the behavior of the first-contact miscible process on a ternary diagram.

Fig. 3 is a ternary diagram with the points  $O$ ,  $P$ , and  $V$  representing the oil, LPG, and dry gas, respectively [5].

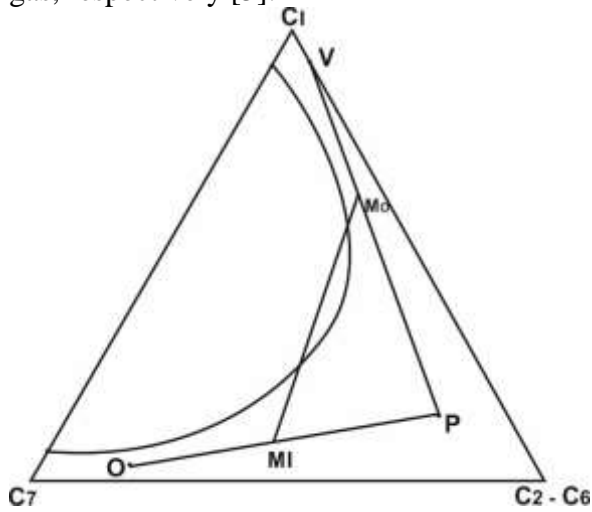


Fig. 3. Ternary diagram illustrating the single-contact miscible process

The oil and LPG are miscible in all proportions. A mixing zone at the oil–LPG interface will grow as the front advances through the reservoir. At the rear of the LPG slug, the dry gas and LPG are miscible and a mixing zone will also be created at this interface. If the dry gas–LPG mixing zone overtakes the LPG–oil mixing zone, miscibility will be maintained unless the contact of the two zones yields mixtures inside the two-phase region (see line  $M_0 M_1$ , fig. 3).

Reservoir pressures sufficient to achieve miscibility are required. This limits the application of LPG processes to reservoirs having pressures at least of the order of 100 bara. Reservoirs with pressures less than this might be amenable to alcohol flooding, another single-contact miscible process, since alcohols tend to be soluble with both oil and water (the drive fluid in this case). The two main problems with alcohols are that they are expensive and they become diluted with connate water during a flooding process, which reduces the miscibility with the oil. Alcohols that have been considered are in the C1–C4 range.

Multiple-contact, or dynamic, miscible processes do not require the oil and displacing fluid to be miscible immediately on contact but rely on chemical exchange between the two phases for miscibility to be achieved. Fig.

4 illustrates the high-pressure (lean-gas) vaporizing process [6].

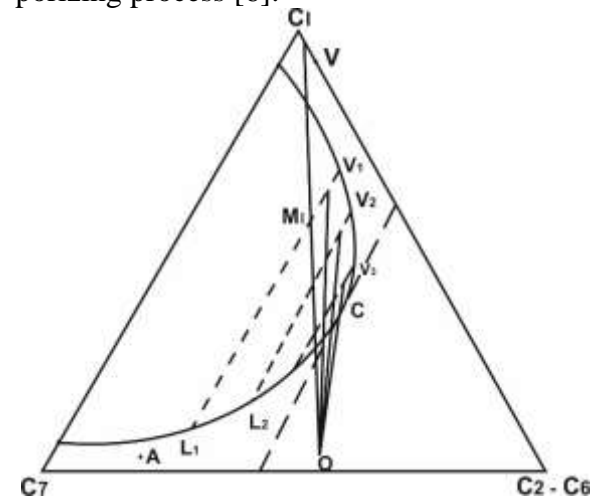


Fig. 4. Ternary diagram illustrating the multicontact dry gas miscible process

The temperature and pressure are constant throughout the diagram at reservoir conditions. A vapor denoted by  $V$  in fig. 3, consisting mainly of methane and a small percentage of intermediates, will serve as the injection fluid. The oil composition is given by the point  $O$ . The following sequence of steps occurs in the development of miscibility:

1. The injection fluid  $V$  comes in contact with crude oil  $O$ . They mix, and the resulting overall composition is given by  $M_1$ . Since  $M_1$  is located in the two-phase region, a liquid phase  $L_1$  and a vapor phase  $V_1$  will form with the compositions given by the intersections of a tie line through  $M_1$  with the bubble point and dew point curves, respectively.

2. The liquid  $L_1$  has been created from the original oil  $O$  by vaporization of some of the light components. Since the oil  $O$  was at its residual saturation and was immobile due to  $K_{ro}$ 's being zero, when a portion of the oil is extracted, the volume, and hence the saturation, will decrease and the oil will remain immobile. The vapor phase, since  $K_{rg}$  is greater than zero, will move away from the oil and be displaced downstream.

3. The vapor  $V_1$  will come in contact with fresh crude oil  $O$ , and again the mixing process will occur. The overall composition will yield two phases,  $V_2$  and  $L_2$ . The liquid again remains immobile and the vapor moves

downstream, where it comes in contact with more fresh crude.

4. The process is repeated with the vapor phase composition moving along the dew point curve,  $V1-V2-V3$ , and so on, until the critical point,  $c$ , is reached. At this point, the process becomes miscible. In the real case, because of reservoir and fluid property heterogeneities and dispersion, there may be a breaking down and a reestablishment of miscibility.

Behind the miscible front, the vapor phase composition continually changes along the dew point curve. This leads to partial condensing of the vapor phase with the resulting condensate being immobile, but the amount of liquid formed will be quite small. The liquid phase, behind the miscible front, continually changes in composition along the bubble point. When all the extractable components have been removed from the liquid, a small amount of liquid will be left, which will also remain immobile. There will be these two quantities of liquid that will remain immobile and will not be recovered by the miscible process. In practice, operators have reported that the vapor front travels anywhere from 6 to 12 meters from the well bore before miscibility is achieved.

The high-pressure vaporizing process requires a crude oil with significant percentages of intermediate compounds.

It is these intermediates that are vaporized and added to the injection fluid to form a vapor that will eventually be miscible with the crude oil. This requirement of intermediates means that the oil composition must lie to the right of a tie line extended through the critical point on the binodal curve fig. 3. A composition lying to the left, such as denoted by point  $A$ , will not contain sufficient intermediates for miscibility to develop. This is due to the fact that the richest vapor in intermediates that can be formed will be on a tie line extended through point  $A$ . Clearly, this vapor will not be miscible with crude oil  $A$ .

As pressure is reduced, the two-phase region increases. It is desirable, of course, to keep the two-phase region minimal in size. As a rule, pressures of the order of 210 bara or greater and an oil with an American Petroleum Institute (API) gravity greater than 35

are required for miscibility in the high-pressure vaporizing process.

**Inert Gas Injection Processes.** The use of inert gases, in particular carbon dioxide,  $CO_2$ , and nitrogen,  $N_2$ , as injected fluids in miscible processes has become extremely popular. The ternary diagram representation of the process with  $CO_2$  or  $N_2$  is exactly the same as that for the high-pressure vaporizing process except that either  $CO_2$  or  $N_2$  becomes a component and methane is lumped with the intermediates. Typically the one-phase region is largest for  $CO_2$ , with  $N_2$  and dry gas having about the same one-phase size. The larger the one-phase region, the more readily miscibility will be achieved. Miscibility pressures are lower for  $CO_2$ , usually in the neighborhood of 85–100 bara, whereas  $N_2$  and dry gas yield much higher miscibility pressures (i.e., 210 psia or more) [7].

The capacity of  $CO_2$  to vaporize hydrocarbons is much greater than that of natural gas. It has been shown that  $CO_2$  vaporizes hydrocarbons primarily in the gasoline and gas-oil range. This capacity of  $CO_2$  to extract hydrocarbons is the primary reason for the use of  $CO_2$  as an oil recovery agent. It is also the reason  $CO_2$  requires lower miscibility pressures than those required by natural gas. The presence of other diluent gases such as  $N_2$ , methane, or flue gas with the  $CO_2$  will raise the miscibility pressure. The multiple contact mechanism works nearly the same with a diluent gas added to the  $CO_2$  as it does for pure  $CO_2$ . Frequently an application of the  $CO_2$  process in the field will tolerate higher miscibility pressures than what pure  $CO_2$  would require. If this is the case, the operator can dilute the  $CO_2$  with other available gas, which will raise the miscibility pressure but also reduce the  $CO_2$  requirements.

**Conclusions.** Because of differences in density and viscosity between the injected fluid and the reservoir fluid(s), the miscible process often suffers from poor mobility. Viscous fingering and gravity override frequently occur. The simultaneous injection of a miscible agent and a brine was suggested in order to take advantage of the high microscopic displacement efficiency of the miscible process and the high macroscopic dis-

placement efficiency of a waterflood. The improvement was not as good as hoped for since the miscible agent and brine tended to separate due to density differences, with the miscible agent flowing along the top of the porous medium and the brine along the bottom.

The simultaneous injection scheme typically involve the injection of a miscible agent followed by brine or the alternating of miscible agent–brine injection. The latter variation has been named the WAG (water alternate gas) process and has become the most popular. A balance between amounts of injected water and gas must be achieved. Too much gas will lead to viscous fingering and gravity override of the gas, whereas too much water could lead to the trapping of reservoir oil by the water. The addition of foam-generating substances to the brine phase has been suggested as a way to aid in reducing the mobility of the gas phase. Operational problems involving miscible processes include transpor-

tation of the miscible flooding agent, corrosion of equipment and tubing, and separation and recycling of the miscible flooding agent.

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**ХАРАКТЕРНЫЕ ПРОЦЕССЫ В РЕГУЛИРУЕМОМ ЭЛЕКТРОПРИВОДЕ И В ЭНЕРГЕТИЧЕСКОЙ СИСТЕМЕ ПРИ РАБОТЕ ВЕНТИЛЬНОГО ПРЕОБРАЗОВАТЕЛЯ ЧАСТОТЫ**

Составными частями вентиляльных преобразователей частоты применяемых для регулирования производительности насосных агрегатов, являются управляемый выпрямитель, собранный на основе шестипульсной мостовой схемы Ларионова, вставка постоянного тока со сглаживающими реакторами и автономный инвертор тока, собранный по той же схеме, что и выпрямитель.

Вентильный тиристорный мост выпрямителя относительно питающей электрической системы является нагрузкой с нелинейной вольтамперной характеристикой. При подключении к зажимам такой нагрузки синусоидального напряже-

ния она потребляет из сети несинусоидальный ток. Действие несинусоидального тока можно рассматривать в виде действий сложных гармонических колебаний различных частот. Известно, что несинусоидальную функцию времени  $f(\omega t)$ , в том числе и  $i(\omega t)$ , удовлетворяющую условию Дирихле, можно представить тригонометрическим рядом Фурье:

$$i(\omega t) = I_0 + \sum_{v=1}^{\infty} I_M(v) \sin(v\omega t + \varphi(v)), \quad (1)$$

где  $v$ - номер гармоники;  $I_0$  – постоянная составляющая тока;  $I_M$ ,  $\varphi(v)$  – амплитуда и начальная фаза тока  $v$ -ой гармоники;  $\omega = 514 \frac{1}{c}$  - угловая частота, соответствующая стандартной частоте сети  $f=50$  Гц.