IMPROVED OIL RECOVERY PROCESSES

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Abstract

Most of the improved, or enhanced, oil recovery methods in use today are described in this paper. It is designed to provide definitions of the terminology used in the literature for describing various types of recovery processes and to provide an overview of each process. The general areas covered are thermal methods, chemical flooding, miscible gas drives, and improved water flooding using polymers.

Introduction

Approximately 70 percent of the oil discovered in the United States is unrecovered using current technology. In order to lower the U.S. dependence on imported hydrocarbons, our country should both conserve energy and develop techniques to recover oil and gas more efficiently. Numerous methods have been developed to produce oil that has been trapped and left behind in the hydrocarbon reservoir rock. These improved oil recovery (IOR) techniques, or enhanced oil recovery (EOR) techniques, include many processes. Some of these processes have been highly successful and some have not. Continued development of these processes, and especially how to apply them successfully in the field, should be part of our state and national energy policies because the EOR target is large. The target unrecovered oil in place has been estimated to be from 300 to 800 billion barrels. Thus, for every one-percent increase in recovery efficiency, three to eight billion barrels of oil are added to our recoverable reserves.

Oil Recovery Classifications

Oil recovery has traditionally been classified as primary, secondary or tertiary depending on the stage of depletion and the method of operation in the field. Primary, or first, recovery is that which uses the original reservoir energy to produce the fluids. The wells may be flowing or being pumped. Secondary, or second, recovery is that which depends on energy and material being injected into the reservoir to augment natural energy and help displace the fluids toward producing wells. Secondary recovery has traditionally been accomplished by injecting water, natural gas, or both into the reservoir through injection wells. Tertiary, or third, recovery has traditionally been those methods that can be used to mobilize residual oil left behind after secondary recovery.

It has long been recognized that secondary or tertiary recovery methods are economically more effective if initiated before primary (or secondary) production is completed. The early initiation of a method allows both ultimate recovery and rate of recovery to be increased. However, the early initiation of a primary, secondary, or tertiary process tends to make the names (first, etc.) meaningless.

The term enhanced oil recovery (EOR) was coined to overcome the difficulty noted above. The term was normally used to refer to those methods that were called tertiary recovery processes. This refers to those methods in which the previously residual (irreducible) oil saturation is reduced to a lower value by some technique such as injecting a displacing fluid into the field such as a gas or liquid miscible with the oil phase.

As knowledge and experience increased and government regulations affecting both oil prices and taxation levels increased, the definition of EOR expressed above was not always correct. An example is that flooding with water solutions of certain polymers can increase rate of recovery substantially by increasing sweep efficiency; but this process does not affect residual (irreducible) oil saturation. Thus, the term improved oil recovery (IOR).

Improved Oil Recovery Processes

Numerous improved oil recovery (IOR) techniques have been developed during the history of oil production. No attempt will be made in this paper to describe, or even mention, all the existing IOR processes. Several of the most successful, or at least the most popular processes will be discussed. No attempt will be made to say which are the best processes as that depends on local reservoir conditions and local availability and cost of materials needed. The general categories that will be discussed are thermal, gas drives, improved water flooding, and chemical flooding processes.

Thermal Methods

Thermal methods are normally used to increase production rates of heavy oils. They include steam drive, steam soak, forward combustion, and reverse combustion. The first three methods above have been quite successful in some fields. The fourth, reverse combustion, has been successful in some laboratory runs but has not shown any promise in the field. The method involves injecting air into an injection well and igniting the producing well after air breaks through. It was hoped that this approach would be useful for reservoirs containing very heavy oils. Using forward combustion, these have a strong tendency to plug and shut off air flow, resulting in a loss of combustion. Because of its lack of success in the field, reverse combustion will not be further discussed.

A. Steam Drive

Steam drive is an IOR process that involves pattern flooding where steam is injected in a group of wells located such that the steam and oil are driven toward producing wells. The primary benefit obtained by injecting steam is that the heat reduces the viscosity of the reservoir oil and allows it to flow more freely toward the producing wells. There is also evidence that heating a water-oil system shifts relative permeability in favor of oil. Some steam distillation will also occur for most oils.

Steam injection is one of the most successful EOR processes used to date and has improved oil recovery in many locations throughout the world.

B. Steam Soak

Steam soak is also known as cyclic steam injection, huff and puff, or steam stimulation. It is a single-well process that is carried out in three stages. During the first stage, steam is injected into the well for a period of time, usually one week or less. During the second stage, the well is kept shut in for several days to allow heat to diffuse throughout the region the steam contacted. The third stage involves producing the well. In many cases the oil rate after steam soak will be substantially higher than before the well was stimulated. The primary reasons that rates are increased is that heating lowers the viscosity of the oil and the steam injected cleans up the wellbore. The process has been successful in numerous locations, especially in California and Venezuela.

C. Forward Combustion

Forward combustion, or fireflooding, in an oil reservoir involves injecting air, oxygen, or air enriched with oxygen into an injection well and igniting the hydrocarbons in the vicinity of the injector. By continuing to inject air and/or oxygen into the injection well, the combustion front can be propagated towards an injection well. The reservoir will be very hot at the combustion front and the heat front will drive the lighter hydrocarbons forward toward the producer. This process leaves behind a coating of very heavy hydrocarbons, called coke, on the reservoir rock. The coke is widely presumed to be the fuel supply for the combustion method. Thus, the poorest part of the oil is what is burned. Cores taken behind the combustion front have shown that the rock is left very clean behind the front.

Fireflooding has not been as successful on a large scale as steamflooding. However, several forward combustion projects have been both engineering and economic successes.

Gas Drives

Gas drives may be used to maintain pressure in a reservoir or designed to be miscible with the oil. The most widely used gas drives are carbon dioxide, hydrocarbon gases, and nitrogen. Carbon dioxide is the most widely used and is becoming one of the more popular IOR processes in use today.

A. Carbon Dioxide Drive

Carbon dioxide flooding has become the most widely used gas drive during the past few years. This interest in carbon dioxide has become widespread primarily for two reasons: it is relatively inexpensive and it is applicable to many reservoirs. It is used as a displacing fluid that may or may not be miscible with the reservoir oil. The majority of applications, however, involve injecting carbon dioxide under conditions for which it is miscible, or at least partially miscible, with the oil.

Carbon dioxide is not miscible with oil on first contact. After some residence time with the oil, carbon dioxide will strip some of the lighter hydrocarbon components from the crude oil and the carbon dioxide and hydrocarbon mixture can become partially miscible with the oil. The minimum miscibility pressure (MMP) is dependent on the temperature and composition of the oil. The value of the MMP for a specific system can be estimated from correlations, but is best determined by laboratory testing. If a particular project can be designed so that carbon dioxide can be injected above the MMP, the residual (irreducible) oil saturation can usually be lowered significantly. Also, carbon dioxide is highly soluble in oil under most field conditions. This reduces the viscosity significantly and also swells the oil sufficiently to substantially increase the oil relative permeability. This method has been used successfully in numerous locations. Often water slugs are injected alternately with the gas. This is called the WAG (water alternating with gas) process and helps reduce fingering of the gas.

Immiscible carbon dioxide flooding can be conducted in fields where it is not possible or practical to achieve a pressure equal to or above the MMP. This immiscible process still has the advantages of swelling the oil and reducing oil viscosity. However, because it does not reduce the irreducible oil saturation, it has not been nearly as successful as the miscible approach.

B. Cyclic Carbon Dioxide Injection

The Cyclic Carbon Dioxide Injection (CCDI) process is a stimulation process that involves one well only. Carbon dioxide is injected for a period of several days, the well is shut in for a few days to allow the carbon dioxide-oil mixture to approach equilibrium, and then it is produced at a rate higher than before the treatment, until the effects of the stimulation decline to a level that indicates the process should be repeated. The carbon dioxide dissolves in the oil phase and causes the oil to swell and to attain a lower viscosity. The dissolved carbon dioxide also lowers the interfacial tension (IFT) and alters the wettability of the system. These changes, especially the first two, cause the oil mobility to increase. The process is similar to that using steam that is known as cyclic steam injection, steam soak, or steam huff and puff. However, unlike the steam soak process, the CCDI process has not been widely used and as a result, little is known of the CCDI process. Research relating to the process needs to be conducted because many producing wells likely will respond to this treatment. Unpublished verbal reports claim a few very successful trials have been conducted. Also, the process is not as expensive and resource intensive as most enhanced oil recovery (EOR) projects and thus offers an EOR process within the economic reach of small independent producing companies as well as large ones.

As the CCDI process can be expected to increase the radius of drainage of a well, it may be successful in replacing infill drilling needs in some reservoirs, thus saving the large expenditures of resources involved in extensive drilling programs. Also, being a one-well process, it works in zones where the pay is either continuous or discontinuous, whereas many EOR methods are frontal displacement processes and require good communication between wells.

C. Nitrogen

Nitrogen injection into petroleum reservoirs has been used to some extent for many years. It is a very good material to maintain pressure if the structure is such that it is not produced back early. Nitrogen as an injection material has two distinct advantages: 1) it is inexpensive compared to other suitable injection gases, and 2) it is completely noncorrosive in contact with surface and downhole equipment.

Nitrogen, like carbon dioxide, can be used as a partially miscible drive material if conditions are correct. However, its use as a miscible drive is limited to fewer oil compositions and higher minimum miscibility pressures as compared with carbon dioxide. Nitrogen is being used in quite a few locations and its suitability should be investigated for individual cases because of its advantages.

D. Hydrocarbon Gases

Hydrocarbon gases have long been used as an injection material to stimulate oil production. The reinjection of produced gas upstructure in a reservoir has been used extensively to maintain reservoir pressure. Heavy hydrocarbon gases such as liquified petroleum gas have been used as a first contact miscible slug followed by a less expensive dry gas to move the slug through the reservoir. This approach became less attractive in the 1970's because of increases in the value of the solvent.

Gas injection projects have also been conducted in which miscible phases were developed in the reservoir (multiple-contact miscibility). The latter process is somewhat analogous to the miscible carbon dioxide injection process. Although hydrocarbon gas injection is still widely used, economics has caused these processes to lose ground to others such as carbon dioxide.

Improved Water Flooding

Improved water flooding using polymers is a widely used improved oil recovery (IOR) process. Polymer flooding consists of adding polymer to the water used in a waterflood. There are two general reasons for polymer flooding: 1) to improve the water-oil mobility ratio and 2) to improve injection profiles. These two uses will be discussed separately, but it should be pointed out that in many cases recovery can benefit from a combination of the two.

A. Polymers for Mobility Control

Polymer flooding consists of adding polymer to the water used to flood the reservoir and displace oil. The addition of polymer to water increases the apparent viscosity of the water and thereby reduces its mobility. An additional benefit that may be gained is that some polymers decrease the effective permeability to the water phase. The effect of both these changes in the aqueous phase is to reduce the mobility of that phase.

Polymer flooding does not reduce the residual (irreducible) oil saturation in the rock. However, it does improve the water-oil mobility ratio. The polymers do not affect the oil phase, so this improvement (reduction) in mobility ratio occurs solely because of the reduction in the aqueous phase mobility as discussed above.

The result obtained by improving the mobility ratio is to increase the sweep efficiency of the waterflood. It should be noted that polymer flooding is a multiple well pattern process just as with regular waterfloods. The improved mobility ratios obtained with polymers increases both areal and vertical sweep efficiencies.

B. Polymers for Profile Control

A problem inherent in all waterfloods is the early breakthrough of water in highly permeable layers while the lower permeability layers may have little oil displaced from them. One method of delaying water breakthrough until a larger percentage of the oil has been recovered is to decrease the water mobility. This mobility control is what polymer flooding is basically all about. Also, some injection profile improvement can be obtained by treatment with polymer solutions near the wellbore.

A more effective method for improving the injection profile is to plug, or partially plug, high permeability zones that have been watered out. This plugging forces the injection fluid into the tighter stringers and selectively displaces oil from them. The plugging of the high permeability zones decreases the water rate through those zones with a resulting reduction in the producing water-oil ratio. This is accomplished by injecting an inorganic cation that will cross-link previously injected polymer molecules with those already in place and bound to solid surfaces. Also, certain polymers and cross-linking agents can produce a gel-like material in situ that is essentially a solid.

Chemical Flooding

Chemical flooding techniques primarily concern 1) Micellar-Polymer flooding and 2) Alkaline flooding. Some authors include polymer flooding under the heading of chemical flooding, but it was preferred here to list it as a separate technique.

A. Micellar-Polymer Flooding

For many years it has been recognized that a relationship exists between the amount of oil recovered by fluid injection and the interfacial tension (IFT) between the oil and the displacing fluid. In general, it can be concluded that the higher the IFT the poorer the recovery. This is because more oil is trapped in the microscopic pores and that it is more difficult for oil to be displaced though the tiny pore throats for IFT values that are high as compared with those that are low. It can also be concluded that lowering IFT values will increase oil recovery. The limiting case is to lower the IFT to a value of zero. This condition of zero IFT constitutes miscible displacement and theoretically should allow oil to be reduced to a residual (irreducible) value of zero. The enhanced oil recovery technique most directly concerned with reducing IFT values is the micellar-polymer (MP) technique.

An MP process is any that involves injecting a surface-active agent (surfactant) into an oil reservoir to improve the oil recovery. The MP process is the same that is referred to in various places in the literature as surfactant-polymer flooding, microemulsion flooding or detergent flooding. The MP process is often applied as a tertiary flood and is a well pattern flood involving a group of injectors displacing oil toward a group of producers. It is not used as a single-well huff and puff type process.

The process involves designing a micellar slug that is compatible with the reservoir rock-fluid system in which it is to be used. The discussion of the make-up of this slug is beyond the scope of this paper. However, it will be pointed out that the formulation of such a compatible slug is often a long, time-consuming, expensive undertaking. Also, the final slug will likely be expensive and, therefore, it will not be feasible to conduct a continuous flood using the slug. Thus, a relatively small slug will be injected and will be followed by a mobility buffer that is actually a polymer flood. The mobility buffer is designed to propagate the micellar slug through the reservoir without fingering and breaking up the slug.

The micellar-polymer process has not contributed very much to the world's IOR production because of the difficulty in formulating a stable, compatible slug in many reservoirs and because of the poor economics often associated with using the process in specific candidate reservoirs. The process has attracted a lot of attention, however, and has been the subject of numerous studies and field tests because it is potentially applicable to so many reservoirs.

B. Alkaline Flooding

The alkaline flooding process, sometimes called caustic flooding, is one in which an aqueous solution of some alkaline material is injected into a reservoir that contains oil sufficiently acid to react with the alkaline. The alkaline material could be any one of many compounds, but the most widely used are sodium orthosilicate, sodium hydroxide, and sodium carbonate. The crude oils that are most likely to be sufficiently acid to be candidates for this process are fairly heavy oils. The process is dependent on the reaction between acid oil and alkaline injection water to produce surfactants in situ in the reservoir.

The acidity of the oil is characterized by a parameter called the acid number of the oil. The acid number is defined as the milligrams of potassium hydroxide (KOH) required to neutralize (to a pH of 7.0) one gram of crude oil. An acid number of 0.2 mg/gm is considered to be the minimum value to consider using the alkaline flooding process. However, a good candidate should have an acid number of 0.5 mg/gm or greater.

Many operators have been attracted to the alkaline flooding process because it is relatively inexpensive. However, in actual practice, few successful alkaline floods have been conducted and the process is not a significant contributor to IOR reserves in the United States or elsewhere in the world.

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