Chapter 14

# Principles of Waterflooding

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

Primary oil recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water.

Secondary oil recovery refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Waterflooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted.

Tertiary (enhanced) oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. Figure 14-1 illustrates the concept of the three oil recovery categories.

## FACTORS TO CONSIDER IN WATERFLOODING

Thomas, Mahoney, and Winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties

Reservoir Engineering Handbook. https://doi.org/10.1016/B978-0-12-813649-2.00014-1

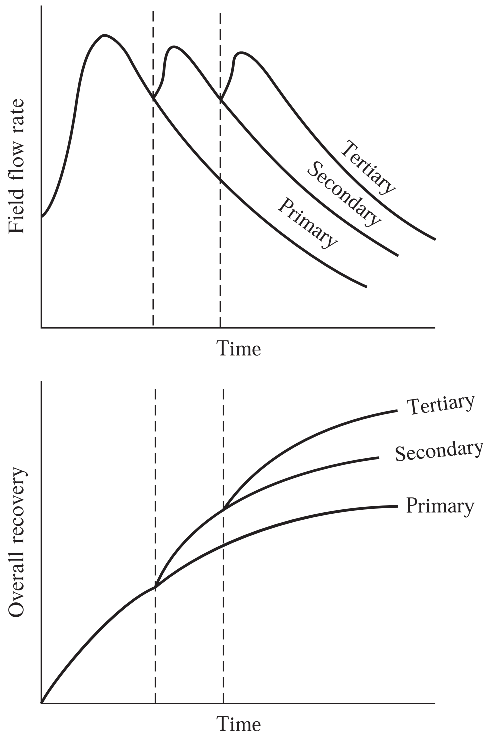


**FIGURE 14-1** Oil recovery categories.

- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity
- Primary reservoir driving mechanisms

Each of these topics is discussed in detail in the following subsections.

## Reservoir Geometry

The areal geometry of the reservoir will influence the location of wells and, if offshore, will influence the location and number of platforms required. The reservoir's geometry will essentially dictate the methods by which a reservoir can be produced through water-injection practices.

An analysis of reservoir geometry and past reservoir performance is often important when defining the presence and strength of a natural water drive and, thus, when defining the need to supplement the natural injection. If a water-drive reservoir is classified as an active water drive, injection may be unnecessary.

## Fluid Properties

The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by waterflooding. The viscosity of the crude oil "$\mu_o$" is considered the most important fluid property that affects the degree of success of a waterflooding project. The oil viscosity has a significant impact of the mobility of the oil "$\lambda_o$" which, in turn, impact the mobility ratio "M". As discussed later in this chapter, the oil mobility is defined by the ratio:

$$\lambda_o = k_o/\mu_o$$

While the mobility ratio is defined as the ratio of the displacing fluid mobility, e.g. "$\lambda_w$", to that of the displaced fluid, e.g. "$\lambda_o$", i.e.

$$M = \lambda_w/\lambda_o = (k_w/k_o)\,(\mu_o/\mu_w)$$

The water displacing efficiency can be enhanced substantially by reducing the mobility ratio "M" by either increasing $\mu_w$ or decreasing $\mu_o$.

## Reservoir Depth

Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Maximum injection pressure will increase with depth. The costs of lifting oil from very deep wells will limit the maximum economic water–oil ratios that can be tolerated, thereby reducing the ultimate recovery factor and increasing the total project operating costs. On the other hand, a shallow reservoir imposes a restraint on the injection pressure that can be used, because this must be less than fracture pressure. In waterflood operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

## Lithology and Rock Properties

Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success include:

- Porosity
- Permeability
- Clay content
- Net thickness

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection program will have only a minor impact on the matrix porosity. Although evidence suggests that the clay minerals present in some sands may clog the pores by swelling and deflocculating when waterflooding is used, no exact data are available as to the extent to which this may occur.

Tight (low-permeability) reservoirs or reservoirs with thin net thickness possess water-injection problems in terms of the desired water-injection rate or pressure. Note that the water-injection rate and pressure are roughly related by the following expression:

$$p_{inj} \propto \frac{i_w}{hk}$$

where:

$p_{inj}$ = water-injection pressure
$i_w$ = water-injection rate
$h$ = net thickness
$k$ = absolute permeability

The above relationship suggests that to deliver a desired daily injection rate of $i_w$ in a tight or thin reservoir, the required injection pressure might exceed the formation fracture pressure.

It should be pointed out the reservoir heterogeneity can greatly impact and reduce the oil recovery by waterflooding. For example, the presence of sealing faults and permeability discontinuities can reduce the effectiveness of water injectors in providing sufficient pressure support to the reservoir. High permeability streaks are another type of reservoir heterogeneity that impact the performance of the waterflood. These high permeability streaks can change the waterflood flow pattern and might result in an early water breakthrough.

## Fluid Saturations

In determining the suitability of a reservoir for a waterflooding process, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility "$\lambda_o$" which contributes to obtaining a higher recovery efficiency.

## Reservoir Uniformity and Pay Continuity

Substantial reservoir uniformity is one of the major physical criterions for successful waterflooding. Some of the following issues regarding reservoir characteristic must be considered and evaluated to study their impacts on the success of a secondary recovery process: must be evaluated:

- if the formation contains a layer of limited thickness with a very high permeability (i.e., **thief zone**), rapid channeling and bypassing will develop unless this zone can be located and shut off, the producing water–oil ratios will become too high for the flooding operation to be considered profitable.

- The lower depletion pressure that may exist in the highly permeable zones will also increase the water-channeling tendency due to the high-permeability variations. Moreover, these thief zones will contain less residual oil than the other layers, and their flooding will lead to relatively lower oil recoveries than other layers.
- Areal continuity of the pay zone is also a prerequisite for a successful waterflooding project. Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the same lens.
- Breaks in pay continuity and reservoir anisotropy caused by depositional conditions, fractures, or faulting need to be identified and described before determining the proper well spanning and the suitable flood pattern orientation.

## Primary Reservoir Driving Mechanisms

As described in Chapter 11, six driving mechanisms basically provide the natural energy necessary for oil recovery:

- Rock and liquid expansion
- Solution gas drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

The recovery of oil by any of the above driving mechanisms is called ***primary recovery***. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as water injection) to supplement the natural energy of the reservoir. The primary drive mechanism and anticipated ultimate oil recovery should be considered when reviewing oil fields for possible development by waterflood. The approximate oil recovery range is tabulated below for various driving mechanisms. Note that these estimates are only approximations and, therefore, oil recovery may fall outside these ranges.

| Driving Mechanism | Oil Recovery Range, % |
|---|---|
| Rock and liquid expansion | 3–7 |
| Solution Gas-cap drive | 20–35 |
| Gas-cap drive | 20–45 |
| Water drive | 35–75 |
| Gravity drainage | <80 |
| Combination drive | 30–60 |

**Volumetric undersaturated oil reservoirs:** These types of reservoirs are identified by initial reservoir pressures that are greater than that of the bubblepoint pressure of existing crude oil systems. The main driving mechanism of a volumetric undersaturated reservoir is attributed to the expansions of the rock connate water, and the crude oil with pressure depletion. In most cases, this mechanism will not recover more than about 5% to 10% of the original oil in place. These reservoirs will offer an opportunity for greatly increasing recoverable reserves if other **I**mproved **O**il **R**ecovery "**IOR**" displacement processes are favorable; e.g. polymer food, thermal recovery injection, …etc.

**Solution gas-drive reservoirs:** These types of reservoirs are initially existing at their crude oil bubblepoint pressures. For a solution gas drive reservoir, the main driving mechanism resulting from the expansion of the liberated solution gas as the reservoir pressure declines below the bubblepoint pressure. They are generally exhibit a relatively low crude oil recovery factors in the range of 20-35% and, therefore, a potential exists for a substantial additional recovery for developing the reservoir by water injection. In genera; they are generally considered the best candidates for waterfloods. It should be pointed out that developing the field by water injection can be viewed as an artificial water-drive mechanism. The typical range of the recovery factor of water-drive reservoir is approximately double of that of obtained from solution gas drive. As a general guideline, a waterflood process in a solution gas-drive reservoir will frequently recover an additional amount of oil equal to that of its primary recovery.

**Gas-cap reservoirs:** The presence of the gas-cap will limit the decrease of the reservoir pressure during production. The magnitude of the decrease in the reservoir pressure depends on the size and the areal extent of the gas-cap. It is possible that the primary driving mechanism resulting from the expansion of the gas-cap is quite efficient to the degree that the field can be effectively managed with production optimization without the need for water injection. In such cases, gas injection in the gas-cap may be considered as a pressure maintenance process to offset and balance high fluid withdrawal rates. Smaller gas-cap drives may be considered as waterflood prospects, but the existence of the gas cap will require greater care to prevent migration of displaced oil into the gas cap. This migration would result in a loss of recoverable oil due to the establishment of residual oil saturation in pore volume of the gas cap, which previously did not exist. If a gas cap is re-pressurized with water injection, it may require a substantial volume of water injection, thereby increasing the project life. However, developing a gas-cap reservoir with waterflood can be considered and may appropriate under one the following conditions:

- The vertical communication between the gas cap and the oil zone is considered poor due to low vertical permeability
- The existence of natural permeability barriers, such as sealing faults, can often restrict the migration of fluids to the gas cap.
- Through the use selective well completion of injection wells to restrict the loss of injection fluid to the gas cap

**Water-drive reservoirs:** Many gas and oil reservoirs are produced by a mechanism termed *water drive*. Hydrocarbon production from the reservoir and the subsequent pressure drop prompt a water encroachment from the aquifer to offset the pressure decline. This response comes in a form of *water influx*, commonly called *water encroachment,* which is attributed to:

- Expansion of the water in the aquifer
- Compressibility of the aquifer rock
- Charge of the aquifer from outcrop water-bearing formation that is located structurally higher than the pay zone

Strong water-drive reservoirs are not usually considered to be good candidates for waterflooding because of the natural water influx. However, in some cases a natural water drive could be supplemented by water injection in order to:

- Support a higher withdrawal rate
- Achieve more uniform areal sweep and coverage by better distributing the injected water volume to different areas of the field
- Better balance Voidage and influx volumes.

## OPTIMUM TIME TO WATERFLOOD

The most common procedure for determining the optimum time to start waterflooding is to calculate:

- Anticipated oil recovery
- Fluid production rates
- Anticipated financial investment
- Availability and quality of the water supply
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors

These calculations should be performed for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected.

Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

- **Reservoir oil viscosity.** Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency.
- **Free gas saturation.** The impact of the free must be considered when plaining field development by water of gas injection:
    - ➢ In **water injection projects**. It is desirable to have an initial gas saturation, possibly as much as 10%. This suggests that there might be benefits of initiating the waterflood process at a pressure that is below the bubble point pressure (discussed in detailed later in this chapter)