Chapter 3: Reservoir Drives

3.1 Introduction

Recovery of hydrocarbons from an oil reservoir is commonly recognised to occur in several recovery stages. These are:

(i) Primary recovery
(ii) Secondary recovery
(iii) Tertiary recovery (Enhanced Oil Recovery, EOR)
(iv) Infill recovery

Primary recovery This is the recovery of hydrocarbons from the reservoir using the natural energy of the reservoir as a drive.

Secondary recovery This is recovery aided or driven by the injection of water or gas from the surface.

Tertiary recovery (EOR) There are a range of techniques broadly labelled 'Enhanced Oil Recovery' that are applied to reservoirs in order to improve flagging production.

Infill recovery Is carried out when recovery from the previous three phases have been completed. It involves drilling cheap production holes between existing boreholes to ensure that the whole reservoir has been fully depleted of its oil.

This chapter discusses primary, secondary and EOR drive mechanisms and techniques.

3.2 Primary Recovery Drive Mechanisms

During primary recovery the natural energy of the reservoir is used to transport hydrocarbons towards and out of the production wells. There are several different energy sources, and each gives rise to a drive mechanism. Early in the history of a reservoir the drive mechanism will not be known. It is determined by analysis of production data (reservoir pressure and fluid production ratios). The earliest possible determination of the drive mechanism is a primary goal in the early life of the reservoir, as its knowledge can greatly improve the management and recovery of reserves from the reservoir in its middle and later life.

There are five important drive mechanisms (or combinations). These are:

(i) Solution gas drive
(ii) Gas cap drive
(iii) Water drive
(iv) Gravity drainage
(v) Combination or mixed drive

Table 3.1 shows the recovery ranges for each individual drive mechanism.

Table 3.1 Recovery ranges for each drive mechanism

Drive Mechanism	Energy Source	Recovery, % OOIP
Solution gas drive	Evolved solution gas and expansion	20-30
Evolved gas		18-25
Gas expansion		2-5
Gas cap drive	Gas cap expansion	20-40
Water drive	Aquifer expansion	20-60
Bottom		20-40
Edge		35-60
Gravity drainage	Gravity	50-70

Figure 3.1 Reservoir Pressure Trends for Drive Mechanisms

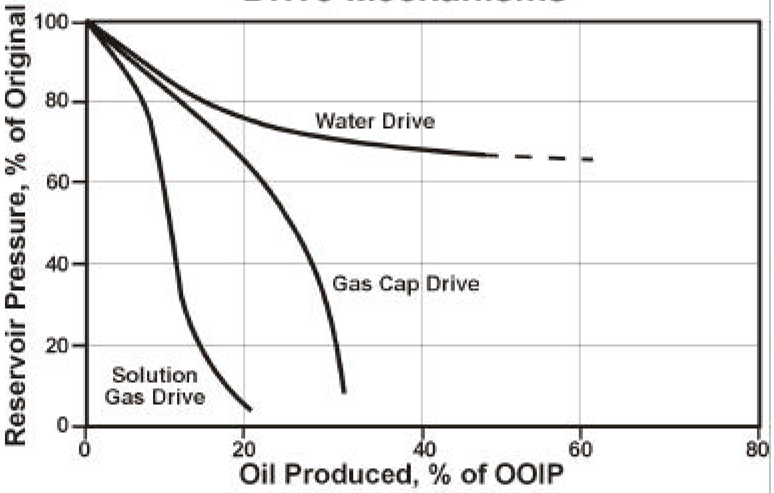
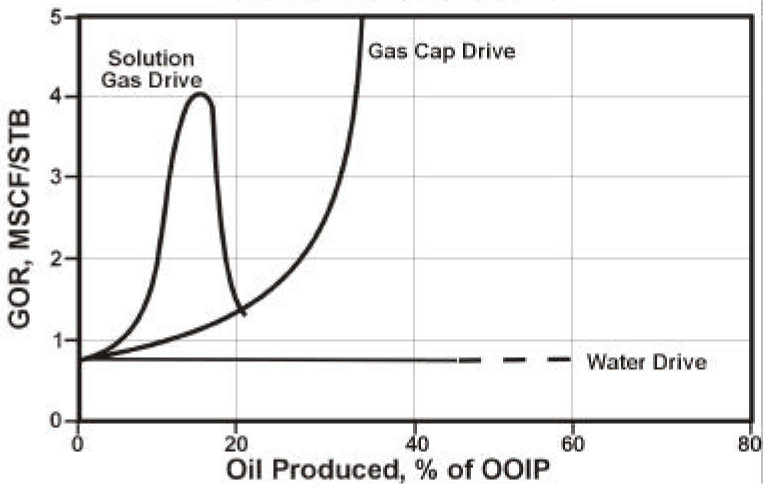


Figure 3.2 GOR Trends for Drive Mechanisms



A combination or mixed drive occurs when any of the first three drives operate together, or when any of the first three drives operate with the aid of gravity drainage.

The reservoir pressure and GOR trends for each of the main (first) three drive mechanisms is shown as Figures 3.1 and 3.2. Note particularly that water drive maintains the reservoir pressure much higher than the gas drives, and has a uniformly low GOR.

3.2.1 Solution Gas Drive

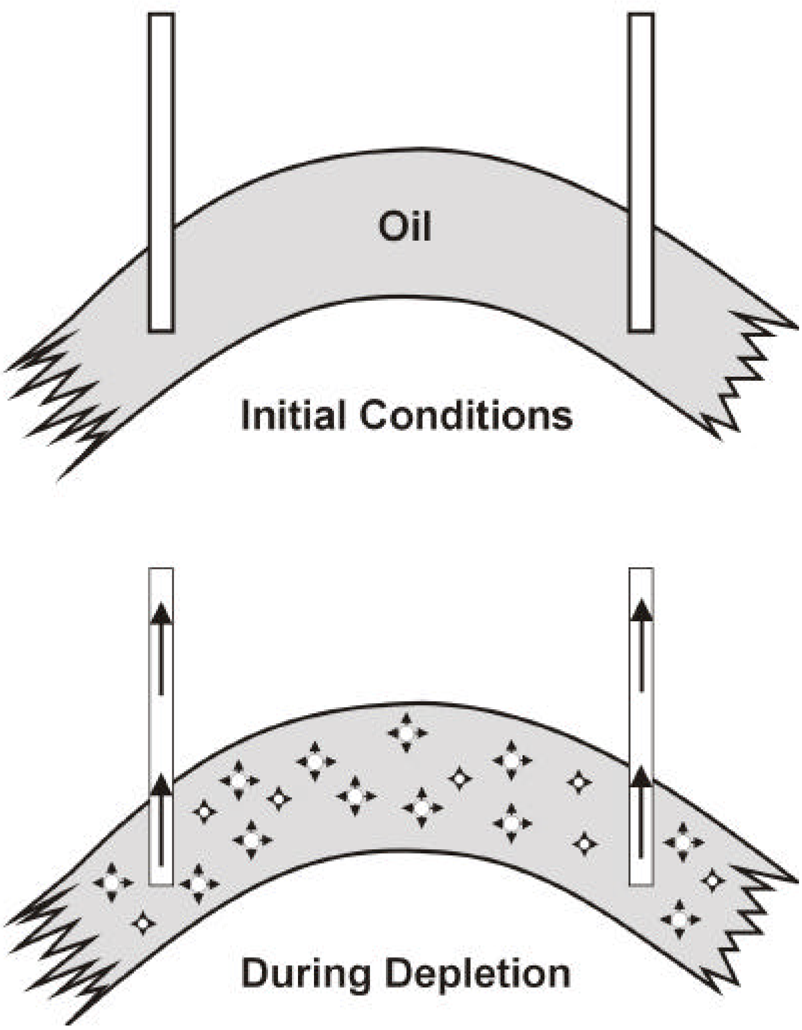
This drive mechanism requires the reservoir rock to be completely surrounded by impermeable barriers. As production occurs the reservoir pressure drops, and the exsolution and expansion of the dissolved gases in the oil and water provide most of the reservoirs drive energy. Small amounts of additional energy are also derived from the expansion of the rock and water, and gas exsolving and expanding from the water phase. The process is shown schematically in Figure 3.3.

A solution gas drive reservoir is initially either considered to be undersaturated or saturated depending on its pressure:

- Undersaturated: Reservoir pressure > bubble point of oil.
- Saturated: Reservoir pressure ≤ bubble point of oil.

For an undersaturated reservoir no free gas exists until the reservoir pressure falls below the bubblepoint. In this regime reservoir drive energy is provided only by the bulk expansion of the reservoir rock and liquids (water and oil).

Figure 3.3 Solution Gas Drive Reservoir



For a saturated reservoir, any oil production results in a drop in reservoir pressure that causes bubbles of gas to exsolve and expand. When the gas comes out of solution the oil (and water) shrink slightly. However, the volume of the exsolved gas, and its subsequent expansion more than makes up for this. Thus gas expansion is the primary reservoir drive for reservoirs below the bubble point.
Solution gas drive reservoirs show a particular characteristic pressure, GOR and fluid production history. If the reservoir is initially undersaturated, the reservoir pressure can drop by a great deal (several hundred psi over a few months), see Figures 3.1 and 3.2.

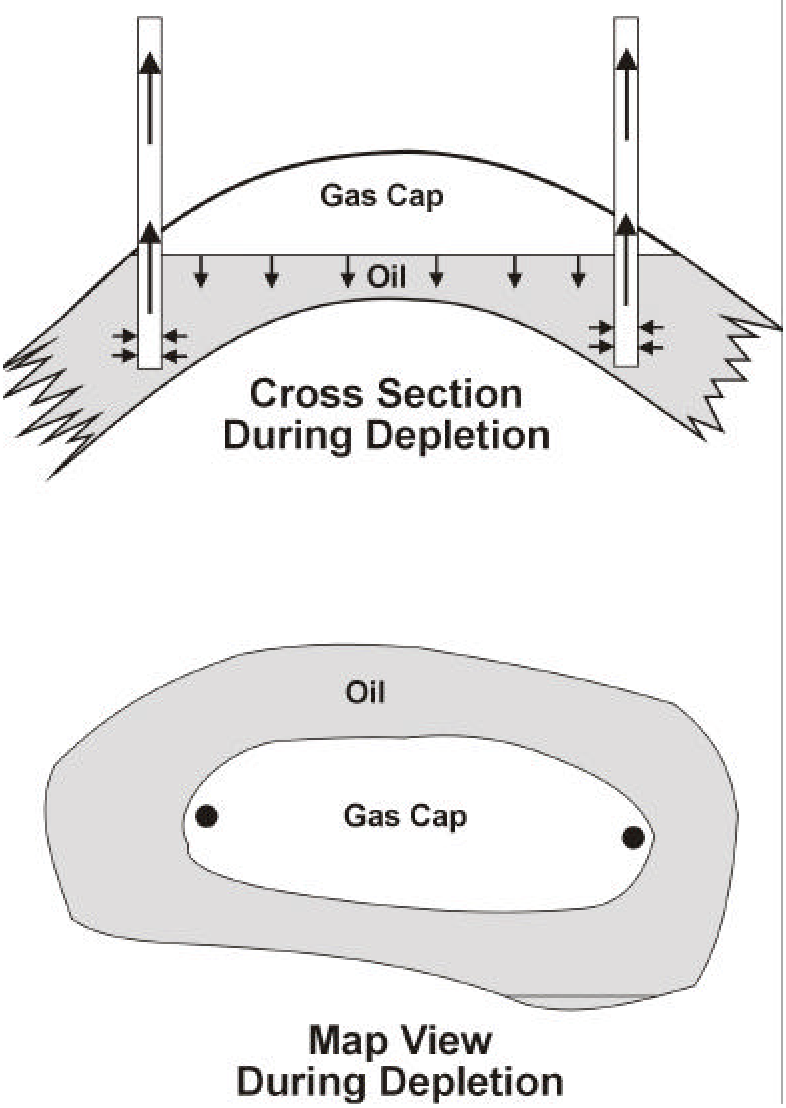
This is because of the small compressibilities of the rock water and oil, compared to that of gas. In this undersaturated phase, gas is only exsolved from the fluids in the well bore, and consequently the GOR is low and constant. When the reservoir reaches the bubble point pressure, the pressure declines less quickly due to the formation of gas bubbles in the reservoir that expand taking up the volume exited by produced oil and hence protecting against pressure drops. When this happens, the GOR rises dramatically (up to 10 times). Further fall in reservoir pressure, as production continues, can, however, lead to a decrease in GOR again when reservoir pressures are such that the gas expands less in the borehole. When the GOR initially rises, the oil production falls and artificial lift systems are then instituted.

Oil recovery from this type of reservoir is typically between 20% and 30% of original oil in place (i.e. low). Of this only 0% to 5% of oil is recovered above the bubblepoint. There is usually no production of water during oil recovery unless the reservoir pressure drops sufficiently for the connate water to expand sufficiently to be mobile. Even in this scenario little water is produced.

3.2.2 Gas Cap Drive

A gas cap drive reservoir usually benefits to some extent from solution gas drive, but derives its main source of reservoir energy from the expansion of the gas cap already existing above the reservoir.

Figure 3.4 Gas Cap Drive Reservoir



The presence of the expanding gas cap limits the pressure decrease experienced by the reservoir during production. The actual rate of pressure decrease is related to the size of the gas cap.

The GOR rises only slowly in the early stages of production from such a reservoir because the pressure of the gas cap prevents gas from coming out of solution in the oil and water. As production continues, the gas cap expands pushing the gas-oil contact (GOC) downwards (Figure 3.4). Eventually the GOC will reach the production wells and the GOR will increase by large amounts (Figures 3.1 and 3.2). The slower reduction in pressure experienced by gas cap reservoirs compared to solution drive reservoirs results in the oil production rates being much higher throughout the life of the reservoir, and needing artificial lift much later than for solution drive reservoirs.

Gas cap reservoirs produce very little or no water.

The recovery of gas cap reservoirs is better than for solution drive reservoirs (20% to 40% OOIP). The recovery efficiency depends on the size of the gas cap, which is a measure of how much latent energy there is available to drive production, and how the reservoir is managed, i.e. how the energy resource is used bearing in mind the geometric characteristics of the reservoir, economics and equity considerations. Points of importance to bear in mind when managing a gas cap reservoir are:

- Steeply dipping reservoir oil columns are best.
- Thick oil columns are best, and are perforated at the base, as far away from the gas cap as possible. This is to maximise the time before gas breaks through in the well.
- Wells with increasing GOR (gas cap breakthrough) can be shut in to reduce field wide GOR.
- Produced gas can be separated and immediately injected back into the gas cap to maintain gas cap pressure.

3.2.3 Water Drive

The drive energy is provided by an aquifer that interfaces with the oil in the reservoir at the oil-water contact (OWC). As production continues, and oil is extracted from the reservoir, the aquifer expands into the reservoir displacing the oil. Clearly, for most reservoirs, solution gas drive will also be taking place, and there may also be a gas cap contributing to the primary recovery. Two types of water drive are commonly recognised:

- Bottom water drive (Figure 3.5)
- Edge water drive (Figure 3.5)

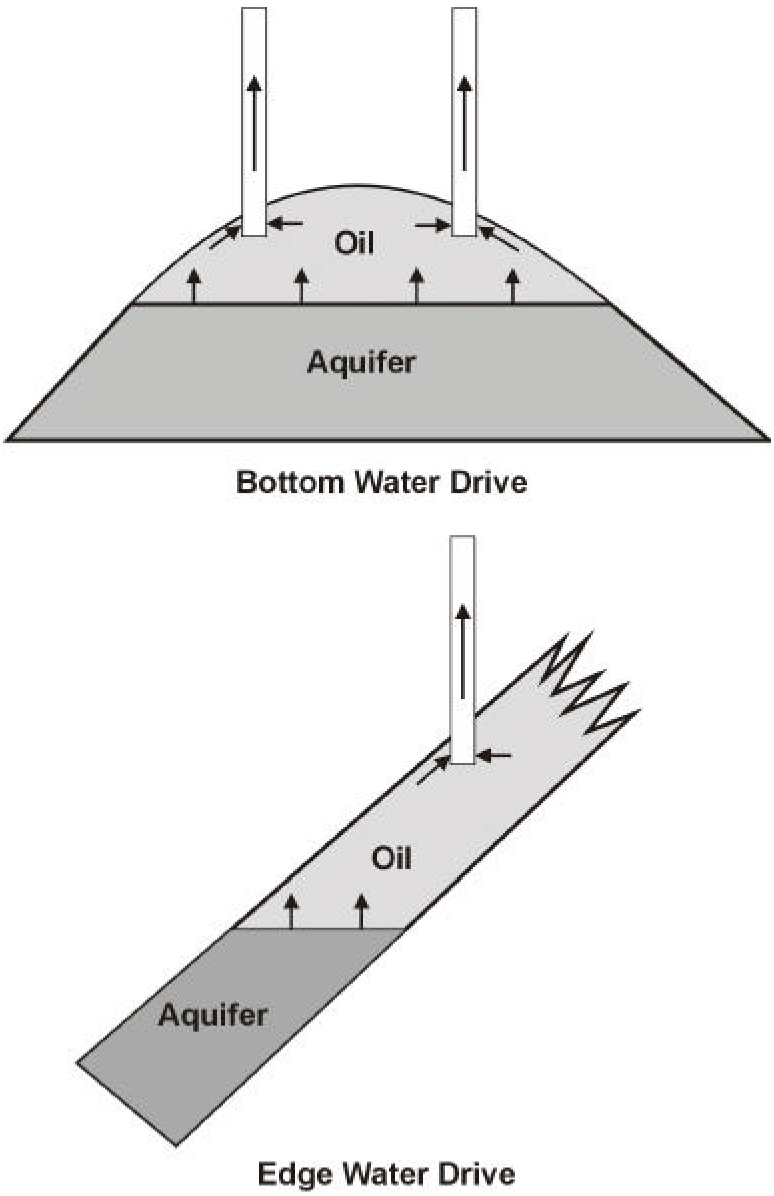
The pressure history of a water driven reservoir depends critically upon:

(i) The size of the aquifer.
(ii) The permeability of the aquifer.
(iii) The reservoir production rate.

If the production rate is low, and the size and permeability of the aquifer is high, then the reservoir pressure will remain high because all produced oil is replaced efficiently with water. If the production rate is too high then the extracted oil may not be able to be replaced by water in the same timescale, especially if the aquifer is small or low permeability. In this case the reservoir pressure will fall (Figure 3.1).

The GOR remains very constant in a strongly water driven reservoir (Figure 3.2), as the pressure decrease is small and constant, whereas if the pressure decrease is higher (weakly water driven reservoir) the GOR increases due to gas exsolving from the oil and water in the reservoir. Likewise the oil production from a strongly water driven reservoir remains fairly constant until water breakthrough occurs.

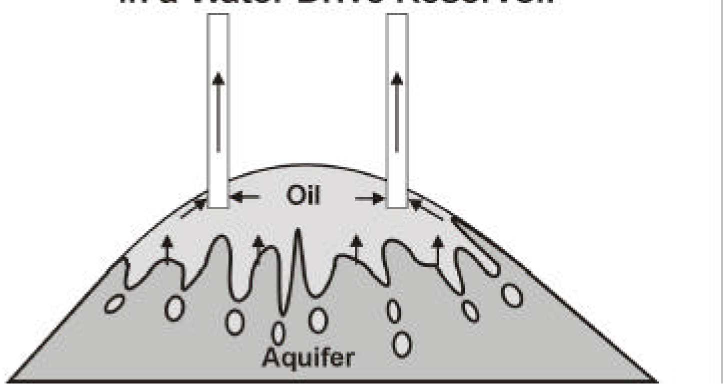
Figure 3.5 Water Drive



Using analogous arguments to the gas cap drive, it can be seen that thick oil columns are again an advantage, but the wells are perforated high in the oil zone to delay the water breakthrough. When water breakthrough does occur the well can either be shut-down, or assisted using gas lift. Reinjection of water into the aquifer is seldom done because the injected water usually just disappears into the aquifer with no effect on aquifer pressure.

The recovery from water driven reservoirs is usually good (20-60% OOIP, Table 3.1), although the exact figure depends on the strength of the aquifer and the efficiency with which the water displaces the oil in the reservoir, which depends on reservoir structure, production well placing, oil viscosity, and production rate. If the ratio of water to oil viscosity is large, or the production rate is high then fingering can occur which leaves oil behind in the reservoir (Figure 3.6).

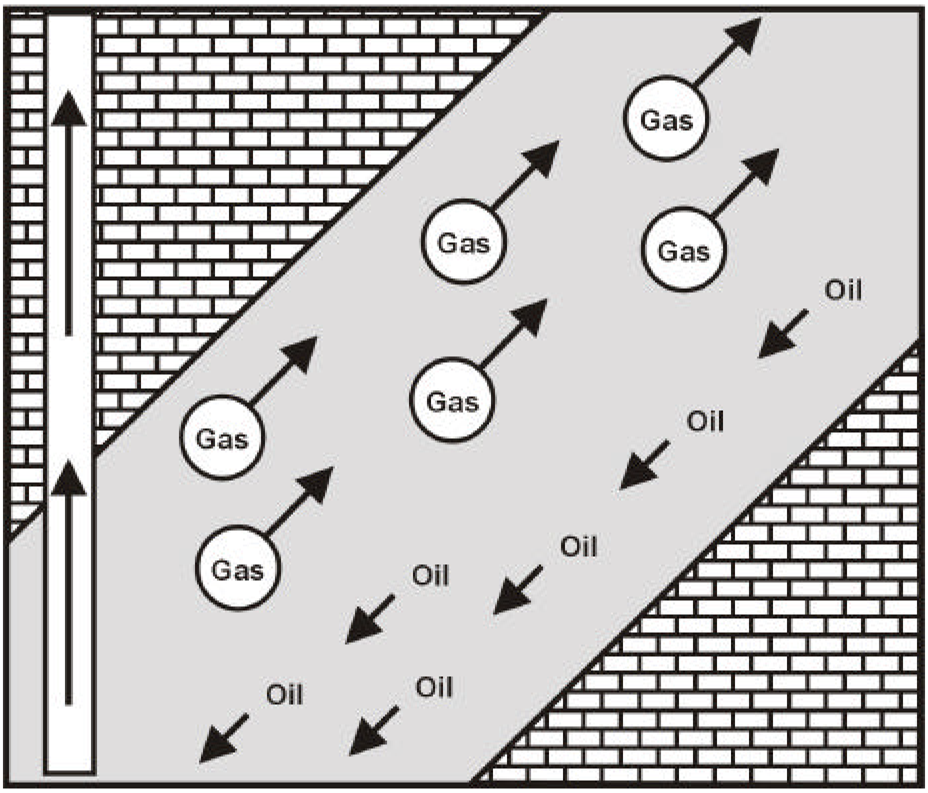
Figure 3.6 A Schematic Example of Fingering in a Water Drive Reservoir



3.2.4 Gravity Drainage

The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms. Figure 3.7 shows production by gravity drainage.

Figure 3.7 Gravity Drainage



The best conditions for gravity drainage are:

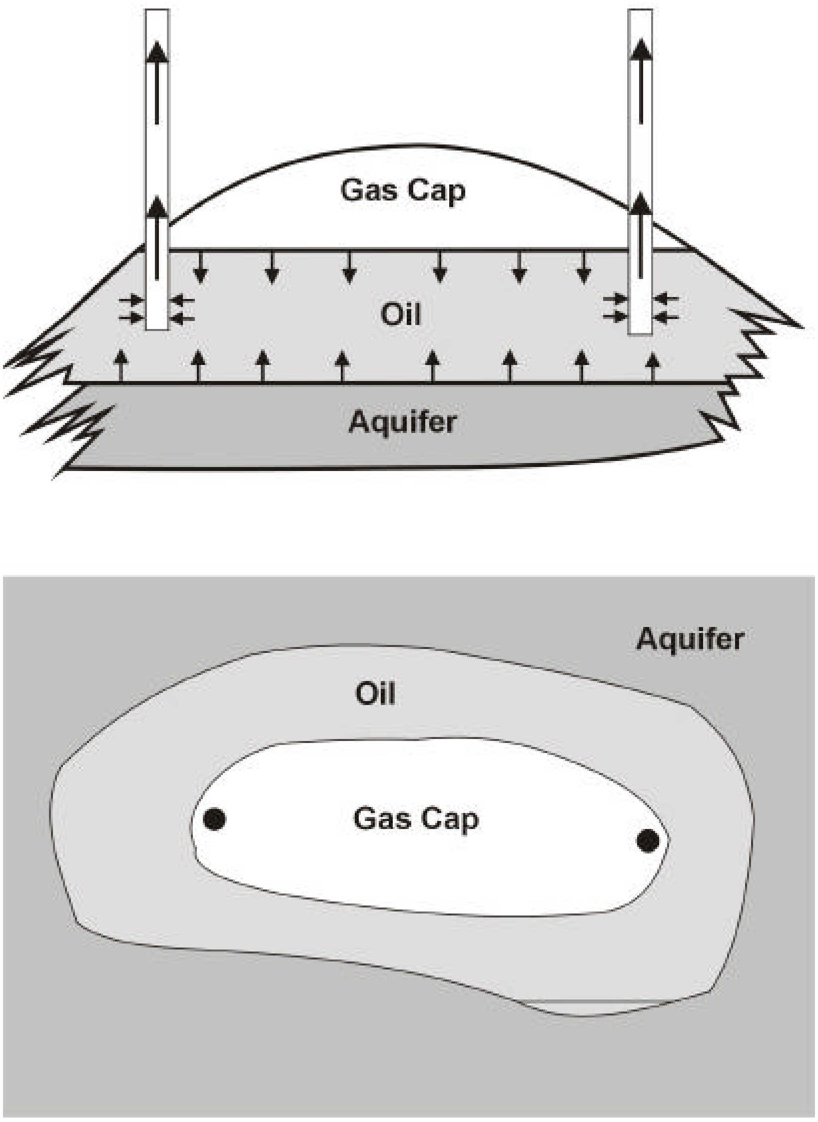
- Thick oil zones.
- High vertical permeabilities.

The rate of production engendered by gravity drainage is very low compared with the other drive mechanisms examined so far. However, it is extremely efficient over long periods and can give rise to extremely high recoveries (50-70% OOIP, Table 3.1). Consequently, it is often used in addition to the other drive mechanisms.

3.2.5 Combination or Mixed Drive

In practice a reservoir usually incorporates at least two main drive mechanisms. For example, in the case shown in Figure 3.8. We have seen that the management of the reservoir for

Figure 3.8 Mixed Drive Reservoir



Map View During Depletion

different drive mechanisms can be diametrically opposed (e.g. low perforation for gas cap reservoirs compared with high perforation for water drive reservoirs). If both occur as in Figure 3.8, a compromise must be sought, and this compromise must take into account the strength of each drive present, the size of the gas cap, and the size/permeability of the aquifer. It is the job of the reservoir manager to identify the strengths of the drives as early as possible in the life of the reservoir to optimise the reservoir performance.

3.3 Secondary Recovery

Secondary recovery is the result of human intervention in the reservoir to improve recovery when the natural drives have diminished to unreasonably low efficiencies. Two techniques are commonly used:

(i) Waterflooding
(ii) Gasflooding

3.3.1 Waterflooding

This method involves the injection of water at the base of a reservoir to;

(i) Maintain the reservoir pressure, and
(ii) Displace oil (usually with gas and water) towards production wells.

The detailed treatment of waterflood recovery estimation, mathematical modelling, and design are beyond the scope of these notes. However, it should be noted that the successful outcome of a waterflood process depends on designs based on *accurate relative permeability data in both horizontal directions*, on the choice of a good injector/producer array, and with full account taken of the local crustal stress directions in the reservoir.

3.3.2 Gas Injection

This method is similar to waterflooding in principal, and is used to maintain gas cap pressure even if oil displacement is not required. Again accurate relperms are needed in the design, as well as injector/producer array geometry and crustal stresses. There is an additional complication in that re-injected lean gas may strip light hydrocarbons from the liquid oil phase. At first sight this may not seem a problem, as recombination in the stock tank or afterwards may be carried out. However, equity agreements often give different percentages of gas and oil to different companies. Then the decision whether to gasflood is not trivial (e.g. Prudhoe Bay, Alaska).

3.4 Tertiary Recovery (Enhanced Oil Recovery)

Primary and secondary recovery methods usually only extract about 35% of the original oil in place. Clearly it is extremely important to increase this figure. Many enhanced oil recovery methods have been designed to do this, and a few will be reviewed here. They fall into three broad categories; (i) thermal, (ii) chemical, and (iii) miscible gas. All are extremely expensive, are only used when economical, and are implemented after extensive SCAL studies have isolated the reservoir rock characteristics that are causing oil to remain unproduced by conventional methods.

3.4.1 Thermal EOR

These processes use heat to improve oil recovery by reducing the viscosity of heavy oils and vaporising lighter oils, and hence improving their mobility. The techniques include:

(i) Steam injection (Figure 3.9).
(ii) *In situ* combustion (injection of a hot gas that combusts with the oil in place, Figure 3.10).
(iii) Microwave heating downhole (3.11).
(iv) Hot water injection.

It is worth noting that the generation of large amounts of heat and the treatment of evolved gas has large environmental implications for these methods. However, thermal EOR is probably the most efficient EOR approach.

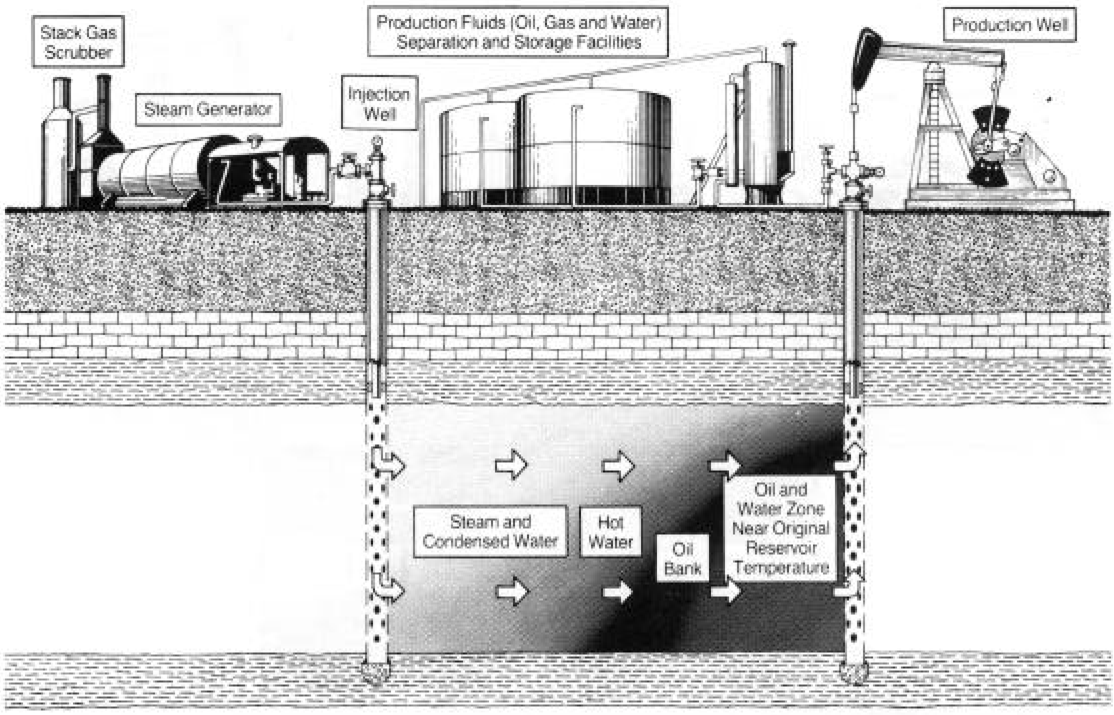


Figure 3.9 Schematic Diagram of Steam Flooding EOR
Heat reduces the viscosity of oil and increases its mobility

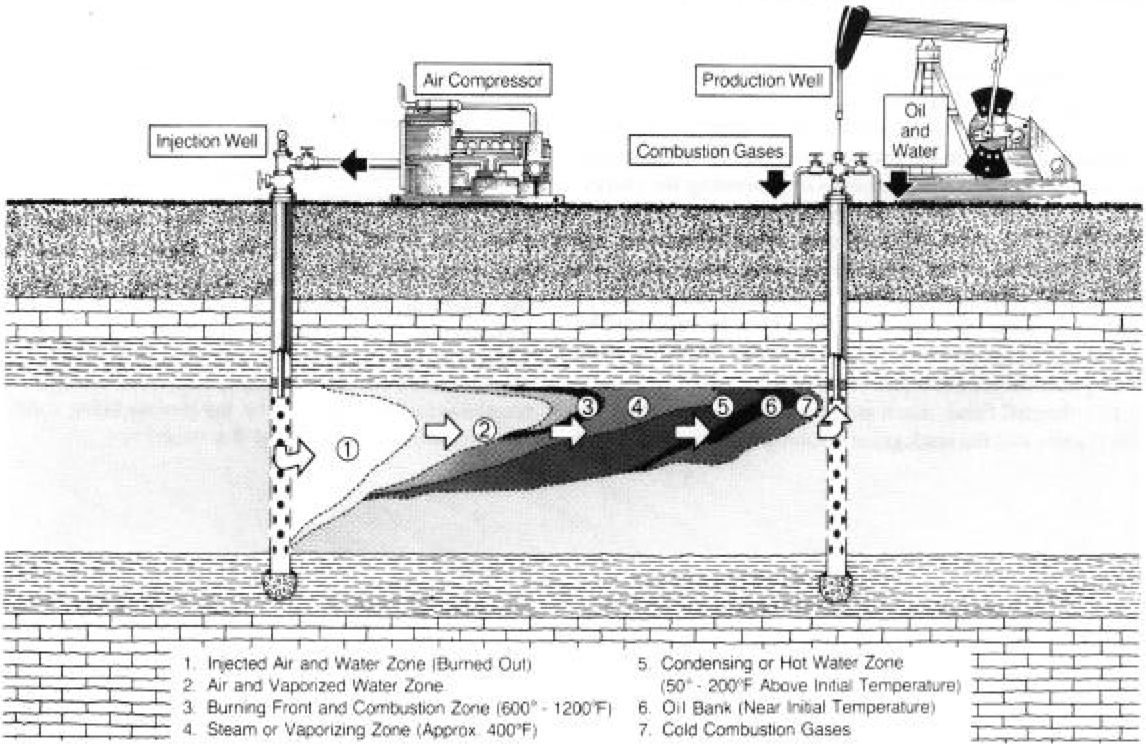
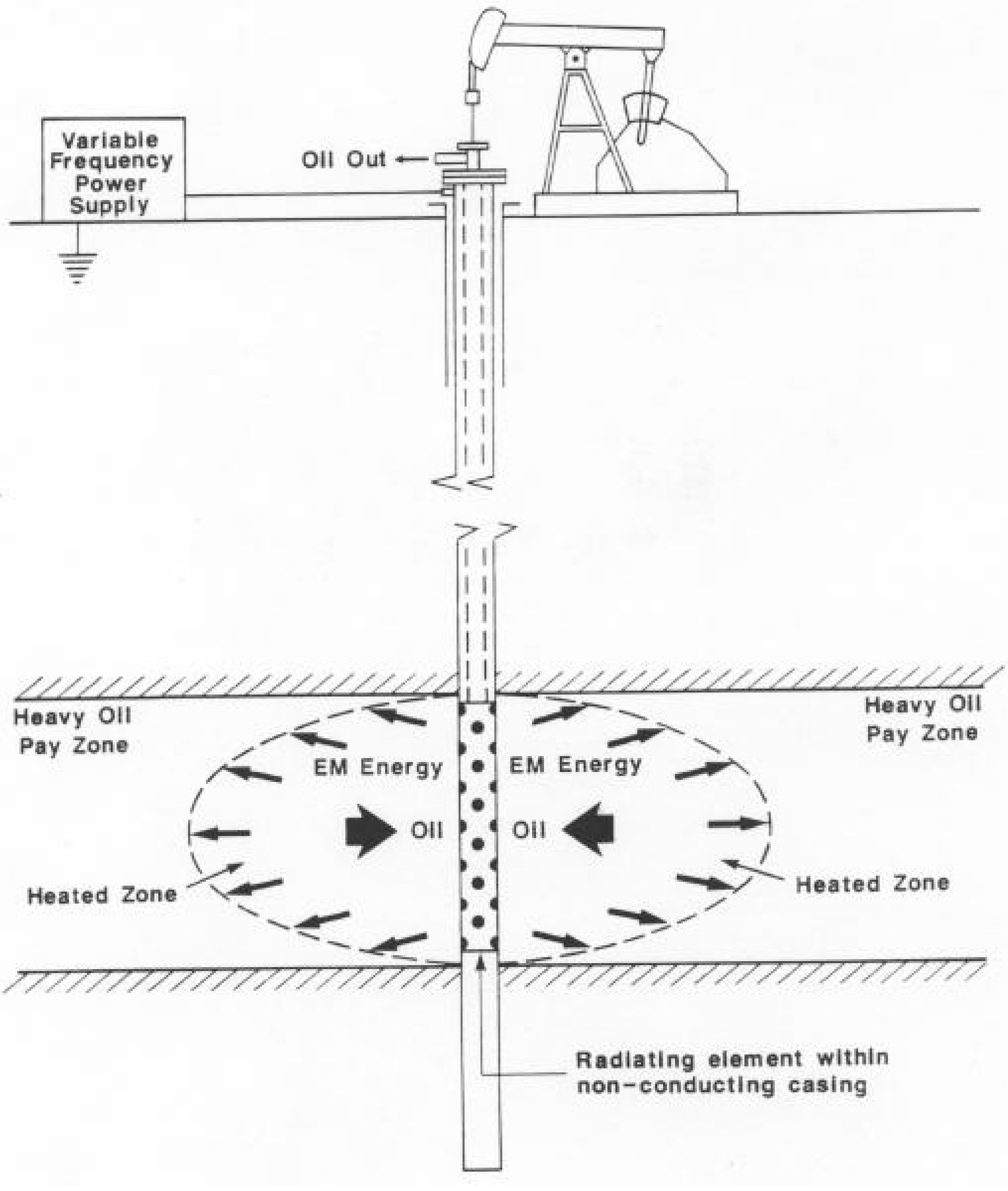


Figure 3.10 Schematic Diagram of In Situ Combustion EOR
Heat and solution of combustion gases reduce the viscosity of oil and increase its mobility

Figure 3.11 Schematic Diagram of Microwave (RF/EM) EOR



3.4.2 Chemical EOR

These processes use chemicals added to water in the injected fluid of a waterflood to alter the flood efficiency in such a way as to improve oil recovery. This can be done in many ways, examples are listed below:

(i) Increasing water viscosity (polymer floods)
(ii) Decreasing the relative permeability to water (cross-linked polymer floods)
(iii) Increasing the relative permeability to oil (micellar and alkaline floods)

(iv) Decreasing S_{or} (micellar and alkaline floods)
(v) Decreasing the interfacial tension between the oil and water phases (micellar and alkaline floods)

An example of chemical EOR is shown in Figure 3.12.

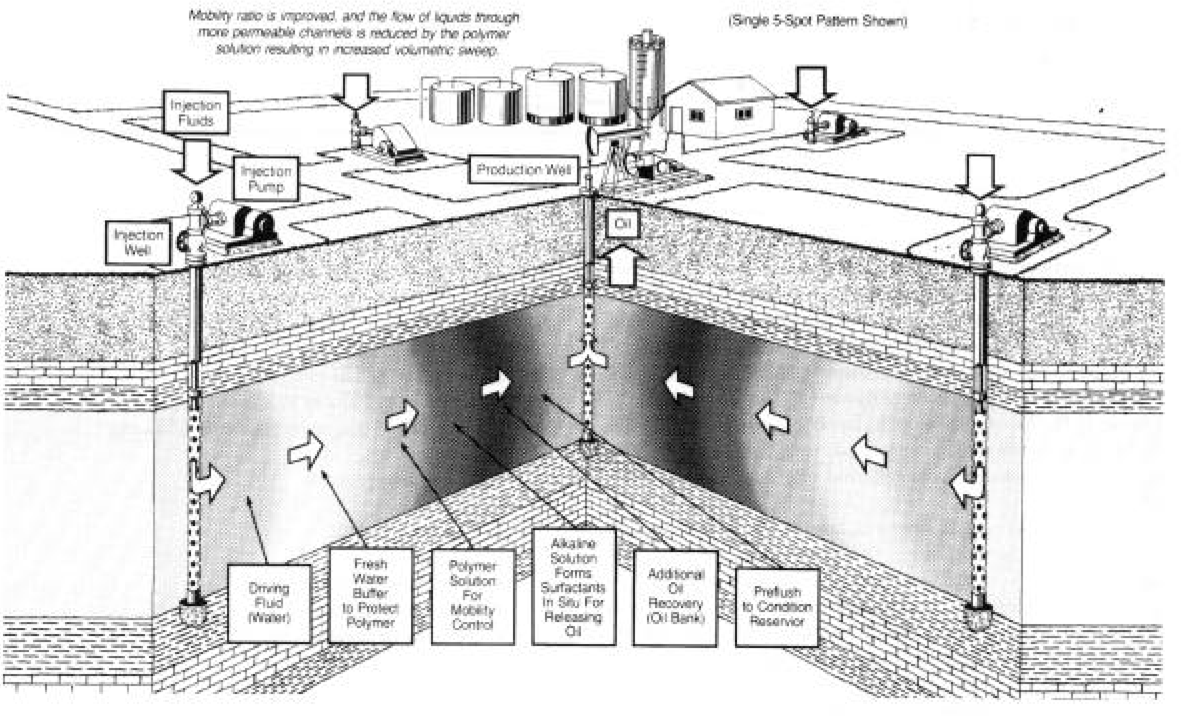


Figure 3.12 Schematic Diagram of Chemical (Alkaline) EOR
Heat and solution of combustion gases reduce the viscosity of oil and increase its mobility

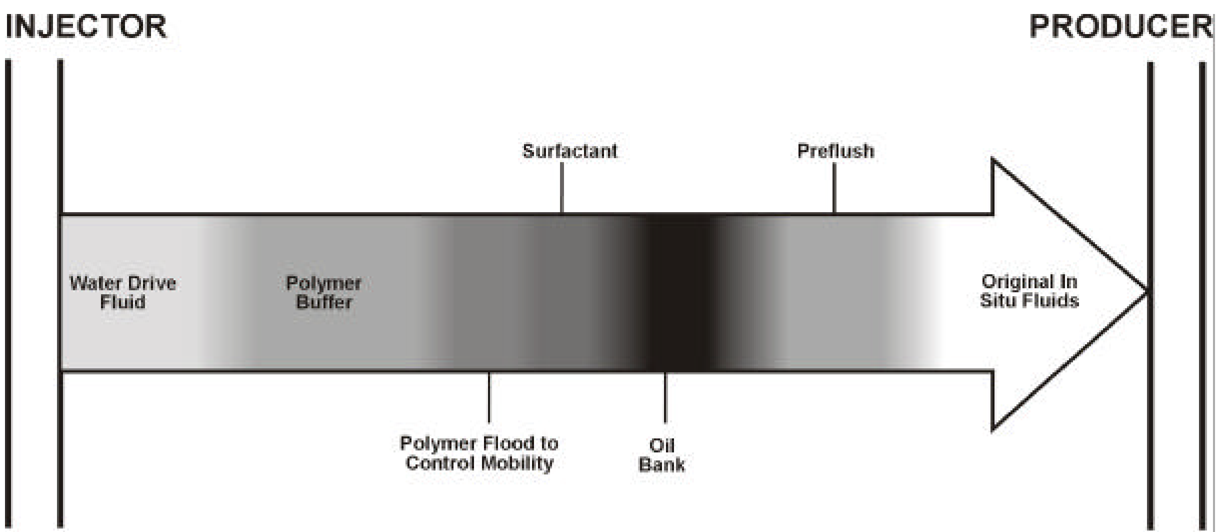


Figure 3.13 The Chemical EOR Process

Chemical flood additives, especially surfactants designed to reduce surface or interfacial tension, are extremely expensive. Thus the whole chemical EOR flood is designed to minimise the amount of surfactants needed, and to ensure that the EOR process is economically successful as well as technically. Chemical flooding is therefore not a simple single stage process. Initially the reservoir is subjected to a preflush of chemicals designed to improve the stability of the interface between the *in-situ* fluids and the chemical flood itself. Then the chemical surfactant EOR flood is carried out. Commonly polymers are injected into the reservoir after the chemical flood to ensure that a favourable mobility ratio is maintained. A buffer to maintain polymer stability follows, then a driving fluid, which is usually water, is injected. Figure 3.13 shows a typical flood sequence. Note that the mobilised oil bank moves ahead of the surfactant flood, and how the total process has reduced the amount of the surfactant fluid used.

3.4.3 Miscible Gas Flooding

This method uses a fluid that is miscible with the oil. Such a fluid has a zero interfacial tension with the oil and can in principal flush out all of the oil remaining in place. In practice a gas is used since gases have high mobilities and can easily enter all the pores in the rock providing the gas is miscible in the oil. Three types of gas are commonly used:

(i) CO_2
(ii) N_2
(iii) Hydrocarbon gases.

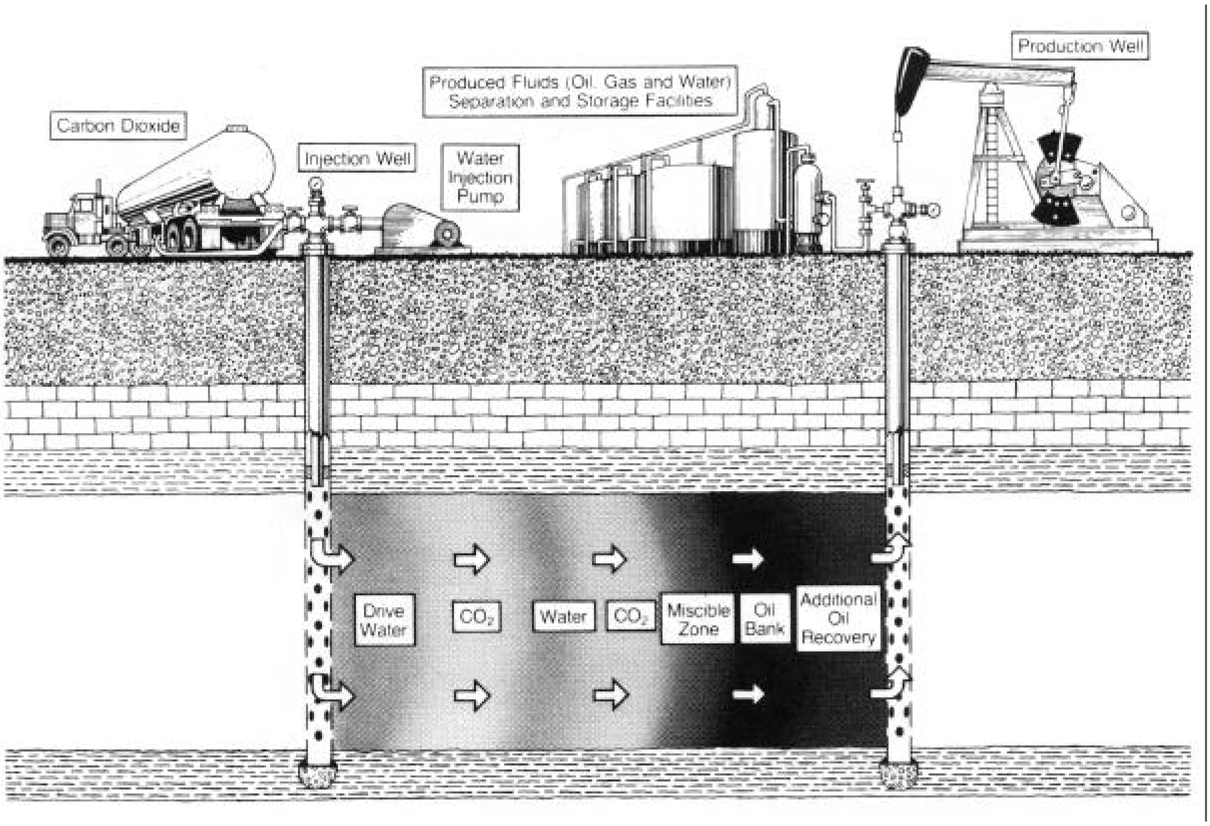


Figure 3.14 Schematic Diagram of Miscible WAG Flooding EOR

All of these are relatively cheap to obtain either from the atmosphere or from evolved reservoir gases. The high mobility of gases can cause a problem in the reservoir flooding process, since gas breakthrough may be early due to fingering, leading to low sweep efficiencies. Effort is then concentrated on trying to improve the sweep efficiency. One such approach is called a miscible WAG (water alternating gas). In this approach water slugs and CO_2 slugs are alternately injected into the reservoir; the idea being that the water slugs will lower the mobility of the CO_2 and lead to a more piston-like displacement with higher flood efficiencies. An additional important advantage of miscible gasflooding is that the gas dissolves in the oil, and this process reduces the oil viscosity, giving it higher mobilities and easier recovery. A WAG flood is shown in Figure 3.14.

3.5 Infill Recovery

Towards the end of the reservoir life (after primary, secondary and enhanced oil recovery), the only thing that can be done to improve the production rate is to carry out infill drilling, directly accessing oil that may have been left unproduced by all the previous natural and artificial drive mechanisms. Infill drilling can involve very significant drilling costs, while the resulting additional production may not be great.