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)

    - ➢ In **gas injection projects.** Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure exists at or above bubble-point pressure.
- ○ **Cost of injection equipment.** This is related to reservoir pressure which indicates that at higher pressures, the cost of injection equipment increases. Therefore, a low reservoir pressure at initiation of injection is desirable.
- ○ **Productivity of producing wells.** A high reservoir pressure is desirable to:
    - ➢ Increase the productivity of producing wells
    - ➢ Extend the flowing period of the wells
    - ➢ Decrease lifting costs
    - ➢ Shorten the overall life of the project
- ○ **Effect of delaying investment on the time value of money.** A delayed investment in injection facilities might be desirable for the standpoint that an opportunity might exist to use the available fund for another investment.
- ○ **Overall life of the reservoir.** Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible.

Some of these six factors act in opposition to others. Thus, the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors in order to develop the most favorable overall economics.

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

IMPACT OF TRAPPED GAS ON OIL RECOVERY BY WATERFLOOD

Numerous experimental and field studies have been conducted to study the effect of the presence of initial gas saturation on waterflood recovery. Early research indicated that the waterflooding of a linear system results in the formation of an oil bank, or zone of increased oil saturation, ahead of the injection water. The moving oil bank will displace a portion of the free water ahead of it, trapping the rest as a residual gas. An illustration of the water saturation profile is shown schematically in Figure 14-2. Several authors have shown through experiments that oil recovery by water is improved as a result of the establishment of **trapped gas saturation,** S_{gt}, in the reservoir.

Willhite (1986) and Craig (1971) indicate that, in some instances, oil recovery can be increased if the reservoir pressure is carefully controlled so as to

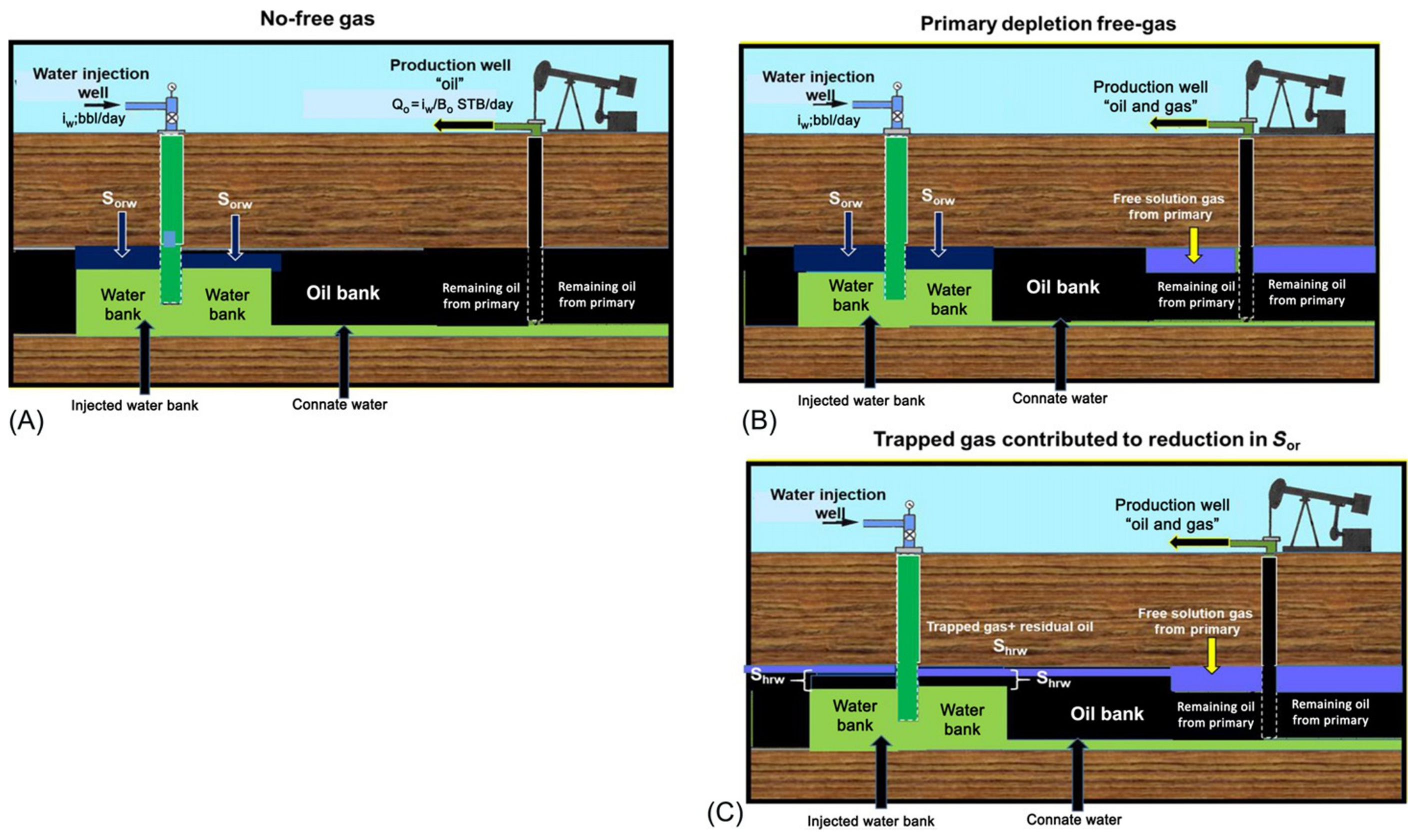

FIGURE 14-2 Three possible scenarios for the impact of gas-saturation on water flood performance.

leave optimum *trapped gas saturation* within the oil bank. The idea is to reduce the value of residual oil saturation to water "S_{orw}" by an amount equal to the trapped gas saturation. For example, if the residual oil saturation is 35% and if a trapped gas saturation can be maintained at 5%, the residual oil saturation would be 30%. In this case, S_{orw} would be reduced by 14.3%. However, selecting and maintaining the optimum reservoir pressure to maintain this critical gas saturation is difficult to achieve in practice.

The theory of this phenomenon of improving overall oil recovery when initial gas exists at the start of the flood is not well established; however, Cole (1969) proposed the following two different theories that perhaps provide insight to this phenomenon.

First Theory

Cole (1969) postulates that since the interfacial tension of a gas–oil system is less than the interfacial tension of a gas–water system, in a three-phase system containing gas, water, and oil, the reservoir fluids will tend to arrange themselves in a minimum energy relationship. In this case, this would dictate that the gas molecules enclose themselves in an oil "blanket." This increases the effective size of any oil globules, which have enclosed some gas. When the oil is displaced by water, the oil globules are reduced to some size dictated by the flow mechanics. If a gas bubble existed on the inside of the oil globule, the amount of residual oil left in the reservoir would be reduced by the size of the gas bubble within the oil globule. As illustrated in Figure 14-3, the external diameters of the residual oil globules are the same in both views. However, in view b, the center of the residual oil globule is not oil, but gas. Therefore, in view b, the actual residual oil saturation is reduced by the size of the gas bubble within the oil globule.

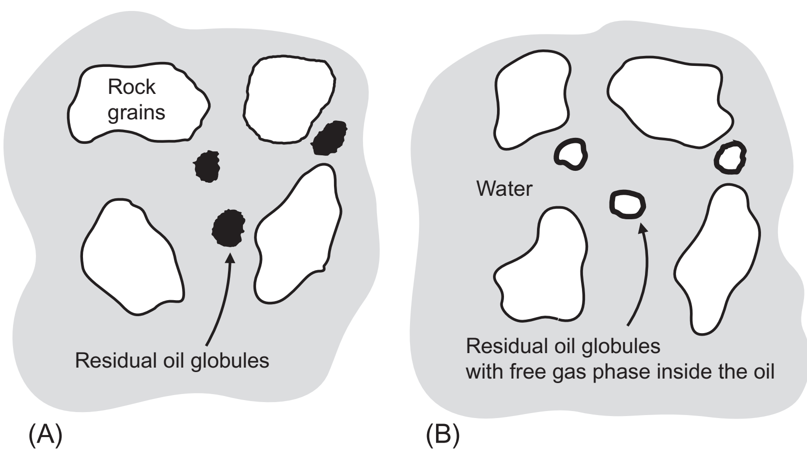

FIGURE 14-3 Effect of free gas saturation on S_{orw} (first theory). *(After Cole, F., 1969).*

Second Theory

Cole (1969) points out that reports on other laboratory experiments have noted the increased recovery obtained by flooding cores with air after waterflooding. These cores were classified as water-wet at the time the laboratory experiments were conducted. On the basis of these experiments, it was postulated that the residual oil saturation was located in the larger pore spaces, since the water would be preferentially pulled into the smaller pore spaces by capillary action in the water-wet sandstone. At a later time, when air was flooded through the core, it moved preferentially through the larger pore spaces since it was nonwetting. However, in passing through these large pore spaces, the air displaced some of the residual oil left by water displacement.

It should be pointed that the second trapped-gas theory is more compatible with results from several laboratory studies and fluid flow observations. The increased recovery due to the presence of free gas saturation can be attributed to the fact that as the gas saturation formed, it displaced oil from the larger pore spaces, because it is more nonwetting to the reservoir rock than the oil. Then, as water displaced the oil from the reservoir rock, the amount of residual oil left in the larger pore spaces would be reduced because of occupancy of a portion of this space by gas. This phenomenon is illustrated in Figure 14-4. As shown in Figure 14-4A, there is no free gas saturation and the residual oil occupies the larger pore spaces. In Figure 14-4B, free gas saturation is present and this free gas now occupies a portion of the space originally occupied by the oil. The combined residual saturations of oil and gas in view b are approximately equal to the residual oil saturation of view a.

Craig (1971) presented two graphical correlations that are designed to account for the reduction in the residual oil saturation due to the presence of the trapped gas. The first graphical correlation, shown in Figure 14-5, correlates the trapped gas saturation (S_{gt}) as a function of the initial gas saturation (S_{gi}). The second correlation as presented in Figure 14-6 illustrates the effect of the

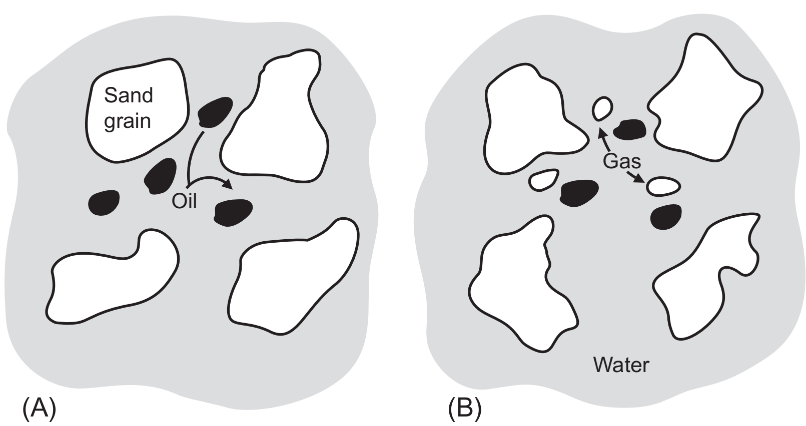

FIGURE 14-4 Effect of free gas saturation on S_{orw} (second theory). *(After Cole, F., 1969).*

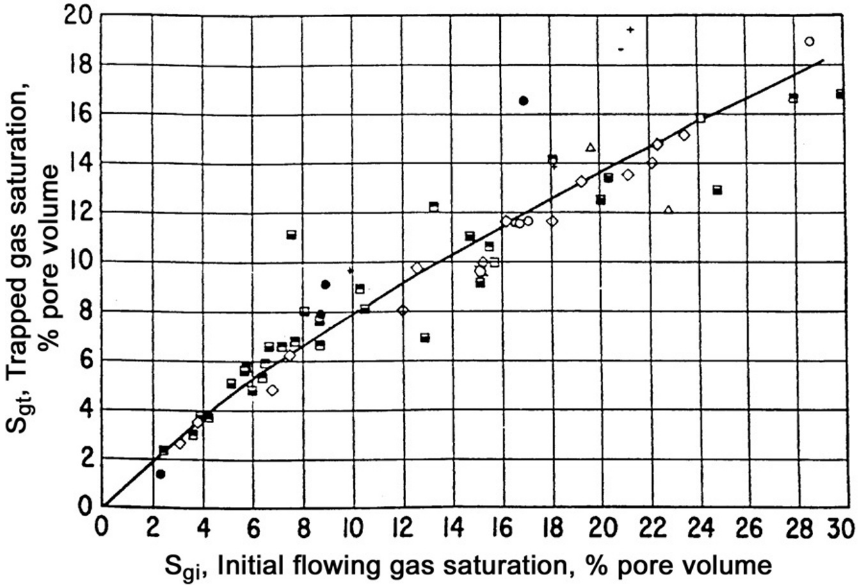

FIGURE 14-5 Relation between S_{gi} and S_{gt}. *(Permission to publish by the Society of Petroleum Engineers).*

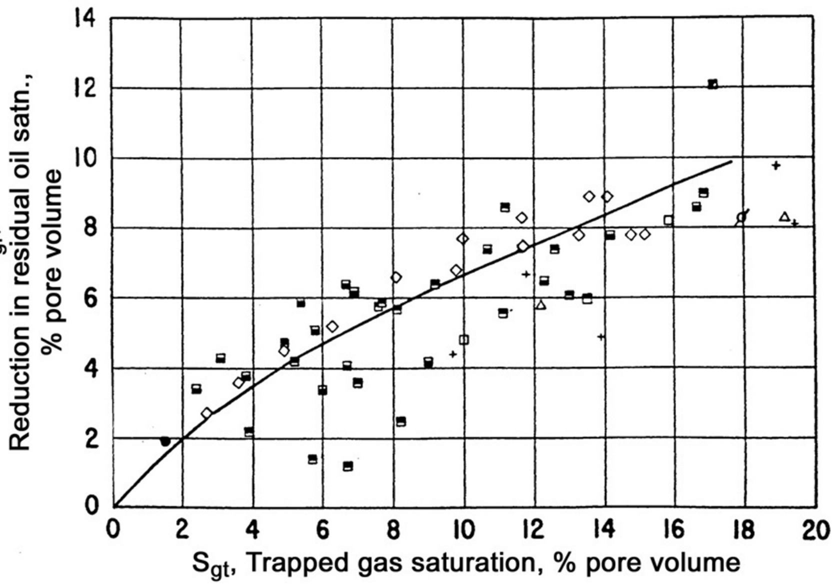

FIGURE 14-6 Effect of S_{gt} on waterflood recovery. *(Permission to publish by the Society of Petroleum Engineers).*

trapped gas saturation on the reduction in residual oil saturation (ΔS_{or}) for preferentially water-wet rock. The two graphic correlations can be expressed mathematically by the following two expressions:

$$S_{gt} = a_1 + a_2 S_{gi} + a_3 S_{gi}^2 + a_4 S_{gi}^3 + \frac{a_5}{S_{gi}} \tag{14-1}$$

and

$$\Delta S_{or} = a_1 + a_2 S_{gt} + a_3 S_{gt}^2 + a_5 S_{gt}^3 + \frac{a_5}{S_{gt}} \tag{14-2}$$

Where:

S_{gi} = initial gas saturation
S_{gt} = trapped gas saturation
ΔS_{or} = reduction in residual oil saturation

Values of coefficients a_1 through a_5 for both expressions are tabulated below:

Coefficients	Equation 14-1	Equation 14-2
a_1	0.030517211	0.026936065
a_2	0.4764700	0.41062853
a_3	0.69469046	0.29560322
a_4	−1.8994762	−1.4478797
a_5	$-4.1603083 \times 10^{-4}$	$-3.0564771 \times 10^{-4}$

Example 14-1

An oil reservoir is being considered for further development by initiating a waterflooding project. The oil–water relative permeability data indicate that the residual oil saturation is 35%. It is projected that the initial gas saturation at the start of the flood is approximately 10%. Calculate the anticipated reduction in residual oil, ΔS_{or}, due to the presence of the initial gas at the start of the flood.

Solution

Step 1. From Figure 14-5 or Equation 14-1, determine the trapped gas saturation, to give:

$$S_{gt} = a_1 + a_2 S_{gi} + a_3 S_{gi}^2 + a_4 S_{gi}^3 + \frac{a_5}{S_{gi}}$$

$$S_{gt} = 8\%$$

Step 2. Estimate the reduction in the residual oil saturation from Figure 14-6 or Equation 14-2, to give:

$$\Delta S_{or} = a_1 + a_2 S_{gt} + a_3 S_{gt}^2 + a_5 S_{gt}^3 + \frac{a_5}{S_{gt}}$$

$$\Delta S_{or} = 5.7\%$$

Therefore, new residual oil saturation is $S_{or} = 33\%$

Khelil (1983) suggests that waterflood recovery can possibly be improved if a so-called "optimum gas saturation" is present at the start of the flood. This optimum gas saturation is given by:

$$\left(S_g\right)_{opt} = \frac{0.001867\, k^{0.634}\, B_o^{0.902}}{\left(\frac{S_o}{\mu_o}\right)^{0.352} \left(\frac{S_{wi}}{\mu_w}\right)^{0.166} \phi^{1.152}} \tag{14-3}$$

Where:

$(S_g)_{opt}$ = optimum gas saturation, fraction
S_o, S_{wi} = oil and initial water saturations, fraction
μ_o, μ_w = oil and water viscosities, cp
k = absolute permeability, md
B_o = oil formation volume factor, bbl/STB
ϕ = porosity, fraction

The above correlation is not explicit and must be used in conjunction with the *material balance equation* (MBE). The proposed methodology of determining $(S_g)_{opt}$ is based on calculating the gas saturation as a function of reservoir pressure (or time) by using both the MBE and Equation 14-3. When the gas saturation as calculated by the two equations is identical, this gas saturation is identified as $(S_g)_{opt}$.

Example 14-2

An absolute permeability of 33 md, porosity of 25%, and an initial water saturation of 30% characterize a saturated oil reservoir that exists at its bubble-point pressure of 1925 psi. The water viscosity is treated as a constant with a value of 0.6 cp. Results of the material balance calculations are given below:

Pressure, psi	Bo, bbl/STB	μ_o, cp	S_o	$S_g = 1 - S_o - S_{wi}$
1925	1.333	0.600	0.700	0.000
1760	1.287	0.625	0.628	0.072
1540	1.250	0.650	0.568	0.132
1342	1.221	0.700	0.527	0.173

Using the above data, calculate the optimum gas saturation.

Solution:

Using the given data and Equation (14-3); perform the necessary the calculations in following tabulated form:

$$(S_g)_{opt} = \frac{0.001867\, k^{0.634}\, B_o^{0.902}}{\left(\frac{S_o}{\mu_o}\right)^{0.352} \left(\frac{S_{wi}}{\mu_w}\right)^{0.166} \phi^{1.152}}$$

Pressure psi	Bo bbl/STB	μ_o cp	MBE S_o	S_g	Equation 14-3 $(S_g)_{opt}$
1925	1.333	0.600	0.700	0.000	—
1760	1.287	0.625	0.628	0.072	0.119
1540	1.250	0.650	0.568	0.132	0.122
1342	1.221	0.700	0.527	0.173	

The calculated value of $(S_g)_{opt}$ at 1540 psi agrees with the value of S_g as calculated from the MBE. Thus, to obtain the proposed additional recovery benefit, the primary depletion should be terminated at a pressure of 1540 psi and water injection initiated.

The Concept of Variable-Bubblepoint Pressure

The injection into a solution gas-drive reservoir usually occurs at injection rates that cause re-pressurization of the reservoir. If pressure is high enough, the trapped gas will dissolve in the oil with no effect on subsequent residual oil saturations. It is of interest to estimate what pressure increases would be required in order to dissolve the trapped gas in the oil system. The pressure is essentially defined as the "new" bubble-point pressure (P_b^{new}). As the pressure increases to the new bubble-point pressure, the trapped gas will dissolve in the oil phase with a subsequent increase in the gas solubility from R_s to R_s^{new}. As illustrated in Figure 14-7, the new gas solubility can be estimated as the sum of the volumes

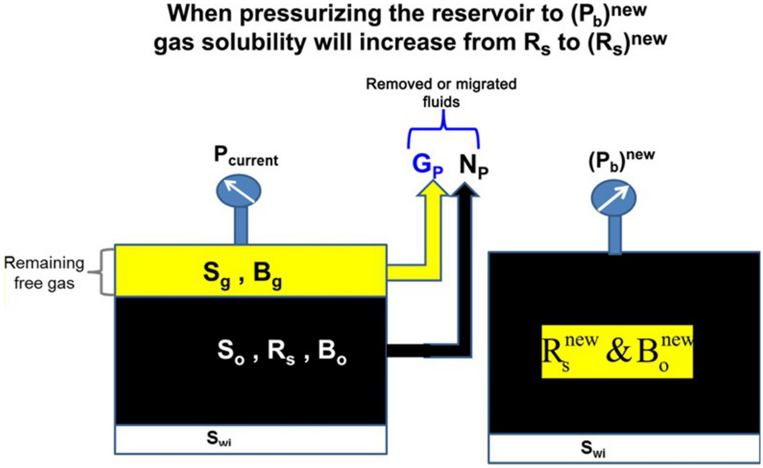

FIGURE 14-7 The concept of variable bubblepoint pressure.