PETROLEUM PRODUCTION ENGINEERING I

LECTURE 10

GAS AND WATER CONING

Coning is a term used to describe the mechanism underlying the upward movement of water and/or the down movement of gas into the perforations of a producing well. Coning can seriously impact the well productivity and influence the degree of depletion and the overall recovery efficiency of the oil reservoirs. The specific problems of water and gas coning are listed below.

• Costly added water and gas handling

• Gas production from the original or secondary gas cap reduces pressure without obtaining the displacement effects associated with gas drive

• Reduced efficiency of the depletion mechanism

• The water is often corrosive and its disposal costly

• The afflicted well may be abandoned early

• Loss of the total field overall recovery

Delaying the encroachment and production of gas and water are essentially the controlling factors in maximizing the field’s ultimate oil recovery. Since coning can have an important influence on operations, recovery, and economics, it is the objective of this chapter to provide the theoretical analysis of coning and outline many of the practical solutions for calculating water and gas coning behavior.

CONING

Coning is primarily the result of movement of reservoir fluids in the direction of least resistance, balanced by a tendency of the fluids to maintain gravity equilibrium. The analysis may be made with respect to either gas or water. Let the original condition of reservoir fluids exist as shown schematically in Figure 9-1, water underlying oil and gas overlying oil. For the purposes of discussion, assume that a well is partially penetrating the formation (as shown in Figure 9-1) so that the production interval is halfway between the fluid contacts.

Production from the well would create pressure gradients that tend to lower the gas-oil contact and elevate the water-oil contact in the immediate vicinity of the well. Counterbalancing these flow gradients is the tendency of the gas to remain above the oil zone because of its lower density and of the water to remain below the oil zone because of its higher density. These counterbalancing forces tend to deform the gas-oil and water-oil contacts into a bell shape as shown schematically in Figure 9-2.

There are essentially three forces that may affect fluid flow distributions around the well bores. These are:

- Capillary forces
- Gravity forces
- Viscous forces

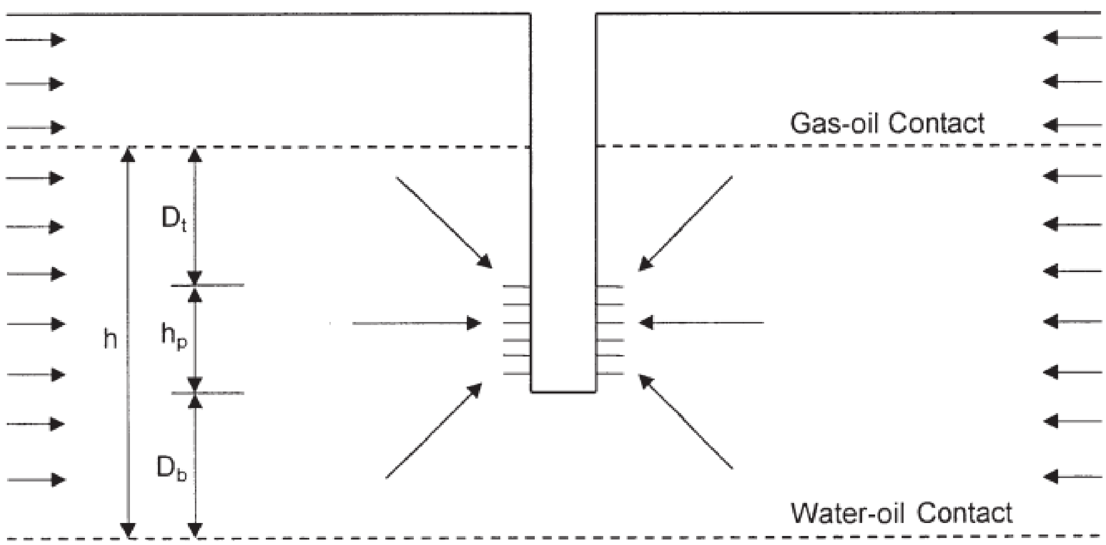

Figure 9-1. Original reservoir static condition.

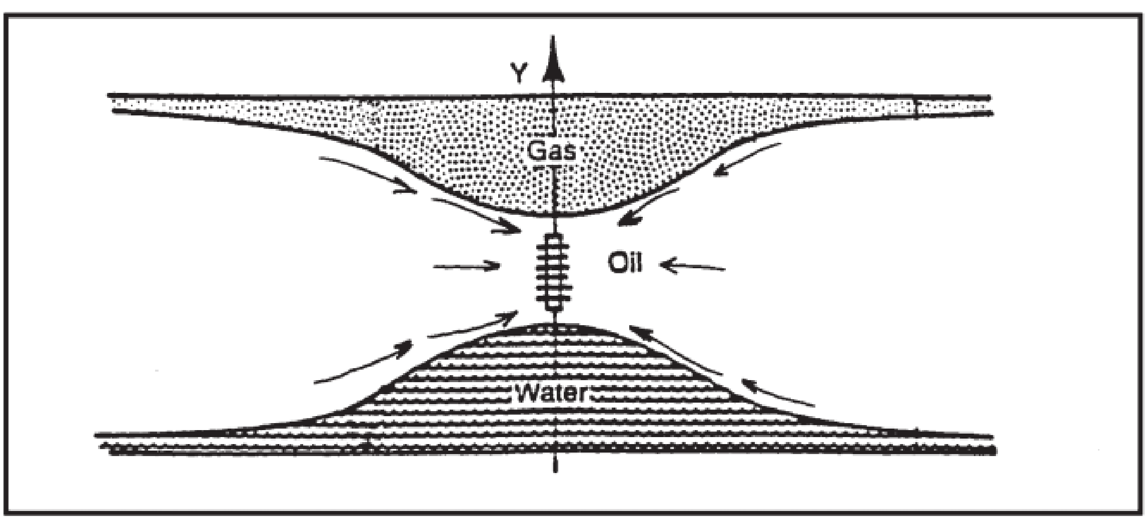

Figure 9-2. Gas and water coning.

Capillary forces usually have negligible effect on coning and will be neglected. Gravity forces are directed in the vertical direction and arise from fluid density differences. The term viscous forces refer to the pressure gradients associated fluid flow through the reservoir as described by Darcy's Law. Therefore, at any given time, there is a balance between gravitational and viscous forces at points on and away from the well completion interval. When the dynamic (viscous) forces at the wellbore exceed gravitational forces, a "cone" will ultimately break into the well.

We can expand on the above basic visualization of coning by introducing the concepts of:

• Stable cone

• Unstable cone

• Critical production rate

If a well is produced at a constant rate and the pressure gradients in the drainage system have become constant, a steady-state condition is reached. If at this condition the dynamic (viscous) forces at the well are less than the gravity forces, then the water or gas cone that has formed will not extend to the well. Moreover, the cone will neither advance nor recede, thus establishing what is known as a stable cone. Conversely, if the pressure in the system is an unsteady-state condition, then an unstable cone will continue to advance until steady-state conditions prevail.

If the flowing pressure drop at the well is sufficient to overcome the gravity forces, the unstable cone will grow and ultimately break into the well. It is important to note that in a realistic sense, stable system cones may only be "pseudo-stable" because the drainage system and pressure distributions generally change. For example, with reservoir depletion, the water-oil contact may advance toward the completion interval, thereby increasing chances for coning. As another example, reduced productivity due to well damage requires a corresponding increase in the flowing pressure drop to maintain a given production rate. This increase in pressure drop may force an otherwise stable cone into a well.

The critical production rate is the rate above which the flowing pressure gradient at the well causes water (or gas) to cone into the well. It is, therefore, the maximum rate of oil production without concurrent production of the displacing phase by coning. At the critical rate, the buildup cone is stable but is at a position of incipient breakthrough.

Defining the conditions for achieving the maximum water-free and/or gas-free oil production rate is a difficult problem to solve. Engineers are frequently faced with the following specific problems:

1. Predicting the maximum flow rate that can be assigned to a completed well without the simultaneous production of water and/or free-gas.

2. Defining the optimum length and position of the interval to be perforated in a well in order to obtain the maximum water and gas-free production rate.

Calhoun (1960) pointed out that the rate at which the fluids can come to an equilibrium level in the rock may be so slow, due to the low permeability or to capillary properties, that the gradient toward the wellbore overcomes it. Under these circumstances, the water is lifted into the wellbore and the gas flows downward, creating a cone as illustrated in Figure 9-2. Not only is the direction of gradients reversed with gas and oil cones, but the rapidity with which the two levels will balance will differ. Also, the rapidity with which any fluid will move is inversely proportional to its viscosity, and, therefore, the gas has a greater tendency to cone than does water. For this reason, the amount of coning will depend upon the viscosity of the oil compared to that of water.

It is evident that the degree or rapidity of coning will depend upon the rate at which fluid is withdrawn from the well and upon the permeability in the vertical direction k_v compared to that in the horizontal direction k_h. It will also depend upon the distance from the wellbore withdrawal point to the gas-oil or oil-water discontinuity.

The elimination of coning could be aided by shallower penetration of wells where there is a water zone or by the development of better horizontal permeability. Although the vertical permeability could not be lessened, the ratio of horizontal to vertical flow can be increased by such techniques as acidizing or pressure parting the formation. The application of such techniques needs to be controlled so that the effect occurs above the water zone or below the gas zone, whichever is the desirable case. This permits a more uniform rise of a water table.

Once either gas coning or water coning has occurred, it is possible to shut in the well and permit the contacts to restabilize. Unless conditions for rapid attainment of gravity equilibrium are present, restabilization will not be extremely satisfactory. Fortunately, bottom water is found often where favorable conditions for gravity separation do exist. Gas coning is more difficult to avoid because gas saturation, once formed, is difficult to eliminate.

There are essentially three categories of correlation that are used to solve the coning problem. These categories are:

• Critical rate calculations

• Breakthrough time predictions

• Well performance calculations after breakthrough

The above categories of calculations are applicable in evaluating the coning problem in vertical and horizontal wells.

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CONING IN VERTICAL WELLS

Vertical Well Critical Rate Correlations

Critical rate Q_{oc} is defined as the maximum allowable oil flow rate that can be imposed on the well to avoid a cone breakthrough. The critical rate would correspond to the development of a stable cone to an elevation just below the bottom of the perforated interval in an oil-water system or to an elevation just above the top of the perforated interval in a gas-oil system. There are several empirical correlations that are commonly used to predict the oil critical rate, including the correlations of:

- Meyer-Garder
- Chierici-Ciucci
- Hoyland-Papatzacos-Skjaeveland
- Chaney et al.
- Chaperson
- Schols

The practical applications of these correlations in predicting the critical oil flow rate are presented over the following pages.

The Meyer-Garder Correlation

Meyer and Garder (1954) suggest that coning development is a result of the radial flow of the oil and associated pressure sink around the wellbore. In their derivations, Meyer and Garder assume a homogeneous system with a uniform permeability throughout the reservoir, i.e., kh = kv . It should be pointed out that the ratio kh/kv is the most critical term in evaluating and solving the coning problem. They developed three separate correlations for determining the critical oil flow rate:

- Gas coning
- Water coning
- Combined gas and water coning

Gas coning

Consider the schematic illustration of the gas-coning problem shown in Figure 9-3.

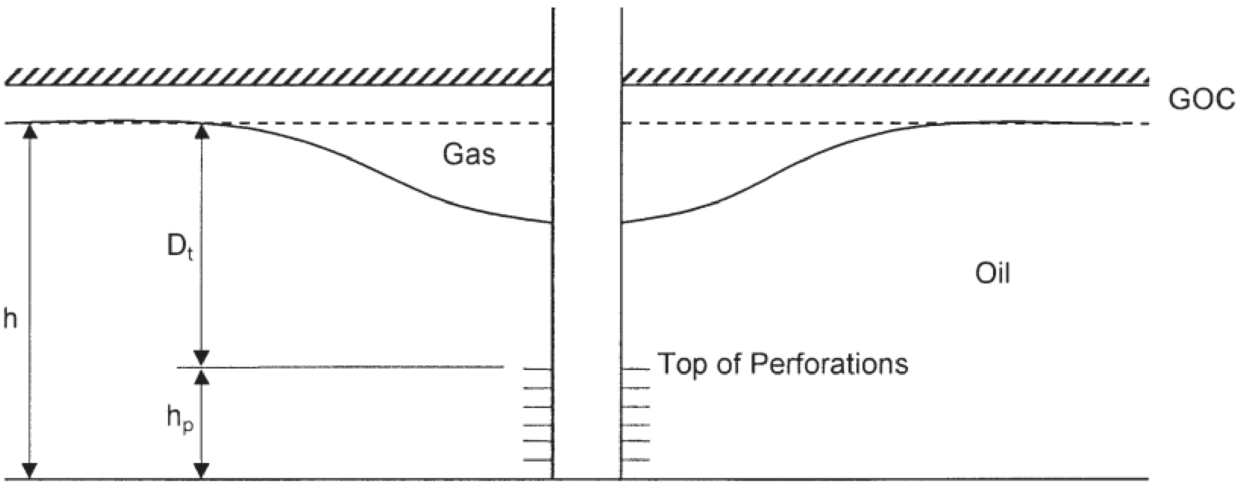

Figure 9-3. Gas coning.

Meyer and Garder correlated the critical oil rate required to achieve a stable gas cone with the following well penetration and fluid parameters:

- Difference in the oil and gas density
- Depth D_t from the original gas-oil contact to the top of the perforations
- The oil column thickness h

The well perforated interval h_p, in a gas-oil system, is essentially defined as

$$h_p = h - D_t$$

Meyer and Garder propose the following expression for determining the oil critical flow rate in a gas-oil system:

$$Q_{oc} = 0.246 \times 10^{-4} \left[\frac{\rho_o - \rho_g}{\ln (r_e/r_w)} \right] \left(\frac{k_o}{\mu_o B_o} \right) \left[h^2 - (h - D_t)^2 \right] \quad (9\text{-}1)$$

where Q_{oc} = critical oil rate, STB/day
ρ_g, ρ_o = density of gas and oil, respectively, lb/ft^3
k_o = effective oil permeability, md
r_e, r_w = drainage and wellbore radius, respectively, ft
h = oil column thickness, ft
D_t = distance from the gas-oil contact to the *top* of the perforations, ft

Water coning

Meyer and Garder propose a similar expression for determining the critical oil rate in the water coning system shown schematically in Figure 9-4.
The proposed relationship has the following form:

$$Q_{oc} = 0.246 \times 10^{-4} \left[\frac{\rho_w - \rho_o}{\ln (r_e/r_w)} \right] \left(\frac{k_o}{\mu_o B_o} \right) (h^2 - h_p^2) \quad (9\text{-}2)$$

where ρ_w = water density, lb/ft^3
h_p = perforated interval, ft

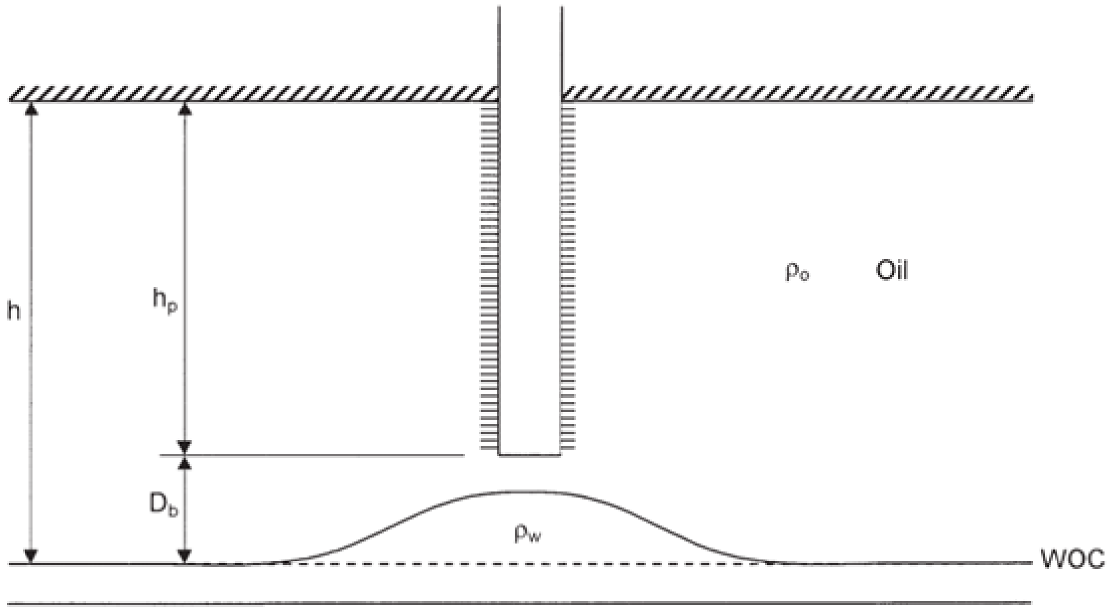

Figure 9-4. Water coning.

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CONING IN VERTICAL WELLS

Simultaneous gas and water coning

If the effective oil-pay thickness h is comprised between a gas cap and a water zone (Figure 9-5), the completion interval h_p must be such as to permit maximum oil-production rate without having gas and water simultaneously produced by coning, gas breaking through at the top of the interval and water at the bottom.

This case is of particular interest in the production from a thin column underlaid by bottom water and overlaid by gas.

For this combined gas and water coning, Pirson (1977) combined Equations 9-1 and 9-2 to produce the following simplified expression for determining the maximum oil-flow rate without gas and water coning:

$$Q_{oc} = 0.246 \times 10^{-4} \left[\frac{k_o}{\mu_o B_o}\right] \frac{h^2 - h_p^2}{\ln(r_e/r_w)} \times \left[(\rho_w - \rho_o)\left(\frac{\rho_o - \rho_g}{\rho_w - \rho_g}\right)^2 + (\rho_o - \rho_g)\left(1 - \frac{\rho_o - \rho_g}{\rho_w - \rho_g}\right)^2\right] \qquad (9-3)$$

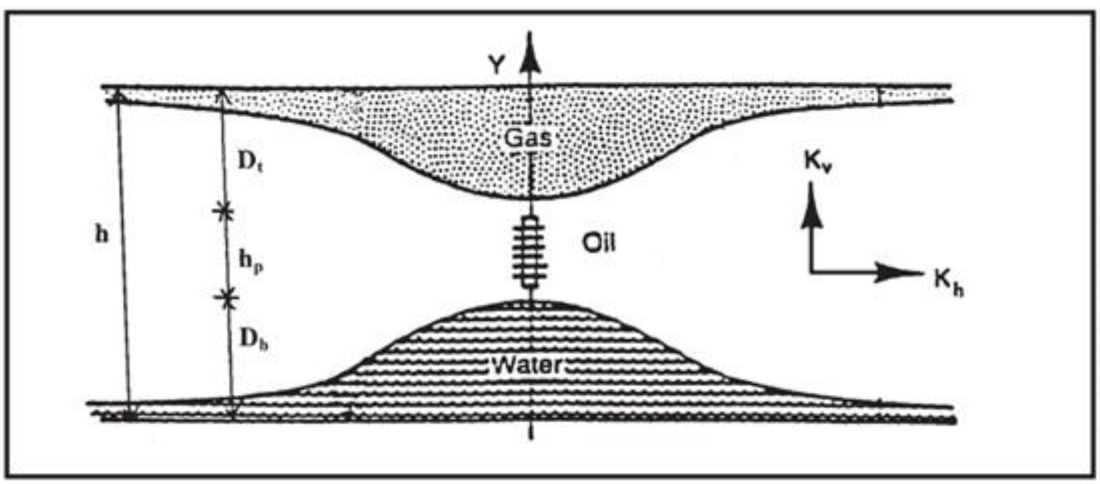

Figure 9-5. The development of gas and water coning.

Example 9-1

A vertical well is drilled in an oil reservoir overlaid by a gas cap. The related well and reservoir data are given below:

horizontal and vertical permeability, i.e., k_h, k_v	= 110 md
oil relative permeability, k_{ro}	= 0.85
oil density, ρ_o	= 47.5 lb/ft^3
gas density, ρ_g	= 5.1 lb/ft^3
oil viscosity, μ_o	= 0.73 cp
oil formation volume factor, B_o	= 1.1 bbl/STB
oil column thickness, h	= 40 ft
perforated interval, h_p	= 15 ft
depth from GOC to top of perforations, D_t	= 25 ft
wellbore radius, r_w	= 0.25 ft
drainage radius, r_e	= 660 ft

Using the Meyer and Garder relationships, calculate the critical oil flow rate.

Solution

The critical oil flow rate for this gas-coning problem can be determined by applying Equation 9-1. The following two steps summarize Meyer-Garder methodology:

Step 1. Calculate effective oil permeability k_o

$$k_o = k_{ro}\, k = (0.85)\,(110) = 93.5 \text{ md}$$

Step 2. Solve for Q_{oc} by applying Equation 9-1

$$Q_{oc} = 0.246 \times 10^{-4} \frac{47.5 - 5.1}{\ln\ (660/0.25)} \frac{93.5}{(0.73)(1.1)} [40^2 - (40 - 25)^2]$$
$$= 21.20 \text{ STB/day}$$

Example 9-2

Resolve Example 9-1 assuming that the oil zone is underlaid by bottom water. The water density is given as 63.76 lb/ft^3. The well completion interval is 15 feet as measured from the top of the formation (no gas cap) to the bottom of the perforations.

Solution

The critical oil flow rate for this water-coning problem can be estimated by applying Equation 9-2. The equation is designed to determine the critical rate at which the water cone "touches" the bottom of the well to give

$$Q_{oc} = 0.246 \times 10^{-4} \left[\frac{(63.76 - 47.5)}{\ln\ (660 / 0.25)}\right]\left(\frac{93.5}{(0.73)(1.1)}\right)[40^2 - 15^2]$$

$$Q_{oc} = 8.13 \text{ STB/day}$$

The above two examples signify the effect of the fluid density differences on critical oil flow rate.

Example 9-3

A vertical well is drilled in an oil reservoir that is overlaid by a gas cap and underlaid by bottom water. Figure 9-6 shows an illustration of the simultaneous gas and water coning.

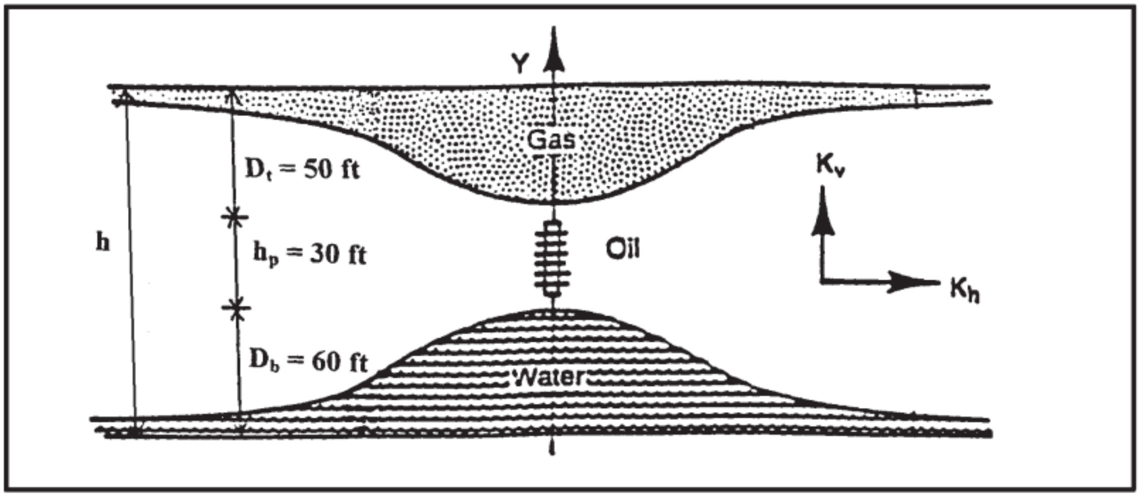

Figure 9-6. Gas and water coning problem (Example 9-3).

The following data are available:

oil density	$\rho_o = 47.5$ lb/ft^3
water density	$\rho_w = 63.76$ lb/ft^3
gas density	$\rho_g = 5.1$ lb/ft^3
oil viscosity	$\mu_o = 0.73$ cp
oil FVF	$B_o = 1.1$ bbl/STB
oil column thickness	$h = 65$ ft
depth from GOC to top of perforations	$D_t = 25$ ft
well perforated interval	$h_p = 15$ ft
wellbore radius	$r_w = 0.25$ ft
drainage radius	$r_e = 660$ ft
oil effective permeability	$k_o = 93.5$ md
horizontal and vertical permeability, i.e., k_h,	$k_v = 110$ md
oil relative permeability	$k_{ro} = 0.85$

Calculate the maximum permissible oil rate that can be imposed to avoid cones breakthrough, i.e., water and gas coning.

Solution

Apply Equation 9-3 to solve for the simultaneous gas- and water-coning problem, to give:

$$Q_{oc} = 0.246 \times 10^{-4} \frac{93.5}{(0.73)(1.1)} \left[\frac{65^2 - 15^2}{\text{Ln}(660/0.25)} \right]$$

$$\times \left[(63.76 - 47.5) \left(\frac{47.5 - 5.1}{63.76 - 5.1} \right)^2 \right.$$

$$\left. + (47.5 - 5.1) \left(1 - \frac{47.5 - 5.1}{63.76 - 5.1} \right)^2 \right] = 17.1 \text{ STB/day}$$

Pirson (1977) derives a relationship for determining the optimum placement of the desired h_p feet of perforation in an oil zone with a gas cap above and a water zone below. Pirson proposes that the optimum distance D_t from the GOC to the top of the perforations can determined from the following expression:

$$D_t = (h - h_p) \left[1 - \frac{\rho_o - \rho_g}{\rho_w - \rho_g} \right] \qquad (9-4)$$

where the distance D_t is expressed in feet.

Example 9-4

Using the data given in Example 9-3, calculate the optimum distance for the placement of the 15-foot perforations.

Solution

Applying Equation 9-4 gives

$$D_t = (65 - 15) \left[1 - \frac{47.5 - 5.1}{63.76 - 5.1} \right] = 13.9 \text{ ft}$$

Slider (1976) presented an excellent overview of the coning problem and the above-proposed predictive expressions. Slider points out that Equations 9-1 through 9-4 are not based on realistic assumptions. One of the biggest difficulties is in the assumption that the permeability is the same in all directions. As noted, this assumption is seldom realistic. Since sedimentary formations were initially laid down in thin, horizontal

Sheets, it is natural for the formation permeability to vary from one sheet to another vertically.

Therefore, there is generally quite a difference between the permeability measured in a vertical direction and the permeability measured in a horizontal direction. Furthermore, the permeability in the horizontal direction is normally considerably greater than the permeability in the vertical direction. This also seems logical when we recognize that very thin, even microscopic sheets of impermeable material, such as shale, may have been periodically deposited. These permeability barriers have a great effect on the vertical flow and have very little effect on the horizontal flow, which would be parallel to the plane of the sheets.