Chapter 7
Overburden Pressure and Compressibility of Reservoir Rock

7.1 Overburden Pressure

The overall pressure at any formation depth, as a result of the weight of fluid-saturated rock column, is known as overburden pressure, P_{ov}. The whole pressure at any reservoir depth is the total of the fluid column pressure, P_f, and the overlaying grain column pressure. P_m, as seen in Fig. 7.1 and Eq. (7.1):

$$P_{ov} = P_f + P_m \tag{7.1}$$

The total weight of the overburden is basically applying a compressive force to the formation rock. The pressure in the aperture of the reservoir rock does not come close to the overburden pressure. Normally, pore pressure is known as the reservoir pressure, is approximately 0.5 psi/ft, considering that the reservoir is adequately consolidated, therefore, the overburden pressure is not passed to the fluids in the pore

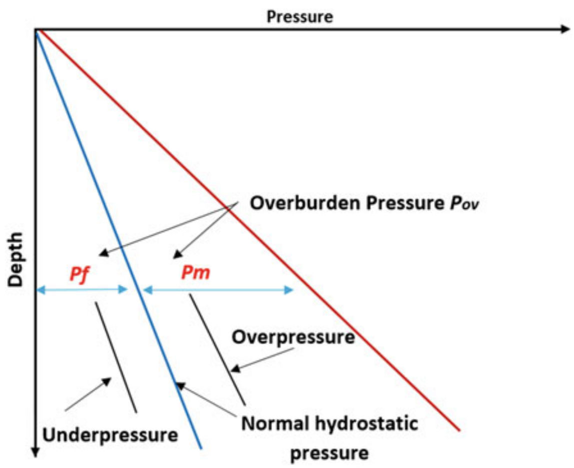

Fig. 7.1 Overburden pressure as the combined matrix and fluid column pressure

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spaces (Tarek 2009). The difference between internal pore pressure and overburden is known as the effective overburden pressure. Through pressure depletion, the internal pore pressure declines and, then, the effective overburden pressure raises. The increase of the effective overburden pressure creates the following effects:

- Decrease the reservoir rock bulk volume.
- Enlarge the sand grains within the aperture.

It should be noted that this pressure is not isotropic but activates vertically. The pressures horizontally depend upon the overburden pressure, but are changed by extra-large scale sub-horizontal tectonic forces, and are affected by local in homogeneities in the crust, such as fractures. Though, to a first an approximation the pressure at depth can commonly be considered to be hydrostatic.

On other words, the pressure in the water phase is depending on the extent to which the fluid column is linked to the Earth's surface. In an open system, the fluid pressure is equal depth × density of the fluid and it's identified as a hydrostatic pressure gradient shown in Fig. 7.2, usually, the pressure gradient is 0.435 psi/ft. Overburden pressure gradient equals the load of the overburden deposit and has a pressure gradient of 1 psi/ft.

Generally, the deviations from hydrostatic pressure take place once the formation fluid is restricted and cannot equilibrate with surface pressure. Usually, the overpressuring is created by:

1. Compaction during fast burial
2. Tectonic compression
3. Hydrocarbon creation and migration (Osborne and Swarbrick 1997).

In very excessive condition, fluid pressure can be either same or go beyond overburden pressures. Unusually, pressures can be lesser than hydrostatic. An underpres-

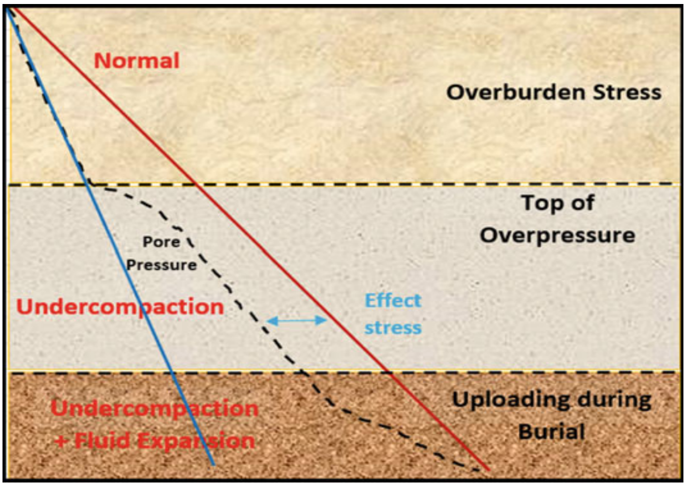

Fig. 7.2 Effect of vertical effective stress to different subsurface conditions

sure is based on the erosional unloading that consequences in raise in pore volume caused by the elastic rebound of the deposit as the overburden are decreased (Arps 1964).

The overburden pressure can be identified as the hydrostatic pressure applies by the weight of fluid-saturated rock column and grain column overlying the depth of rock (Eq. 7.2):

$$P_{ov} = 0.052 \times \rho b \times D \tag{7.2}$$

where:

P_{ov} overburden pressure (psi)
ρ_b formation bulk density (ppg)
D vertical depth (ft)

Equation 7.3 below, its key equation for determining the overburden gradient pressure in field conditions of changing lithological and pore fluid density:

$$P_{ov} = 0.433[(1 - \text{Ø})\rho_{ma} + (\text{Ø}\rho b)] \tag{7.3}$$

where:

Ø Porosity
ρ_f Formation fluid density, gm/cc
ρ_{ma} Matrix density, gm/cc

7.1.1 Pore Pressure

Normally, pore pressure is referring to the overburden pressure which is not supported by rock matrix, but rather by the fluids or gases exist in the formation. Commonly, pore pressure is same as hydrostatic pressure of water column extended from the bottom of the well to the surface. If the reservoir pressure is less than the hydrostatic pressure, in this case, the reservoir called subnormal pressure. Therefore, if the reservoir pressure more than the hydrostatic pressure then it's known as abnormal pressure reservoir depicted in Fig. 7.3.

7.1.2 Effective Pressure

The overburden pressure applies upon a rock to crush it. Consequently, the fluids existing in the pore spaces would be compressed. Therefore, the fluid pressure applies to the rock to stop the rock crushing. In reality, the rock does not crush under the effect of the overburden pressure, but it is a result of the strength of the rock particles

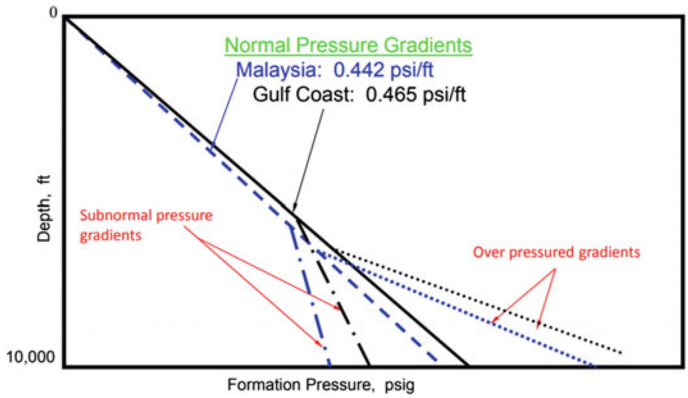

Fig. 7.3 Illustrates normal and abnormal reservoir pressure

and any cementation and the support effect of the fluid pressure. A total effective pressure might be identified as the overburden pressure minus the fluid pressure. Commonly, there are available evidence that the effective pressure the overburden pressure minus around 80% of the fluid pressure.

7.2 Compressibility of Reservoir Rock

Compressibility is a physical fact, which has a major function in the petroleum production system. Therefore, it's an important "drive mechanism" in the production system. Since the pressure drops with fluids production, then, rock grains will be closer and reduces the rock porosity. This phenomenon called rock compressibility.

The rock compressibility has a major effect on the computation of oil initially in place in undersaturated volumetric reservoirs when the edges of the field are unidentified and studies of natural water drive performance.

Almost all hydrocarbons production and formation water is a function of volume expansion when the reservoir pressure drops because of the produce of reservoir fluids. When outer forces exerted on the reservoir rocks, inner stresses are increased and if the stresses are strong enough, this will cause deformation the rock volume and shape. In general, the main compressibility effective on reservoir rock is due to two factors, known as, expansion of the rock grains, because the in situ fluid pressure drops, and the extra formation compaction brought about (Howard 2013). Both of these factors tend to decrease porosity. Rock compressibility is identified as the decrease in pore volume per unit of rock volume with a unit change in reservoir pressure, presented as (Eq. 7.4);

$$C = \frac{1}{V}\left(\frac{dP}{dV}\right)T \tag{7.4}$$

where c is the coefficient of isothermal compressibility, $c \geq 0$, V is Volume (ft^3), P is the pressure exerted of material (Psi), and T is the temperature (°F).

The total compressibility of any formation rock is an effect of two main factors, expansion of the single rock grains, and the extra compaction due to overburden pressure as reservoir pressure declines. In the same time, these factors tend to reduce porosity. The experiments were conducted in a way that would give compressibility measurements reflecting the combination of the two factors and would duplicate the performance of the rock under reservoir conditions. Figure 7.4 displays the apparatus used to estimate rock compressibility.

Typically, the reservoirs overburden pressure is constant but the fluid pressure in pores media changes, which causes changes in the pore volume. During the experimental work, the confining pressure (P_f) on the core sample will change while keeping the pore pressure constant. The gross compaction pressure is the difference between the pore pressures and overburden. This way helps to achieve valuable results during the experiment. The experiment procedure: Core sample is 100% saturated with brine. Core sample is sited in a rubber sleeve. Once pressure outside the rubber sleeve is increased, pore volume decreases and the volume of seeped brine is measured.

In 1953, Hall (1953) presented correlations between porosity and rock compressibility see Fig. 7.5 for numerous reservoirs (sandstone and limestone). All experiments were carried out with an external pressure of 3000 psi and internal pressures from 0 to 1500 psi. In 1958, Fatt (1958) stated that there is no correlation between compressibility and porosity, though the studied porosity was very narrow (10–15%).

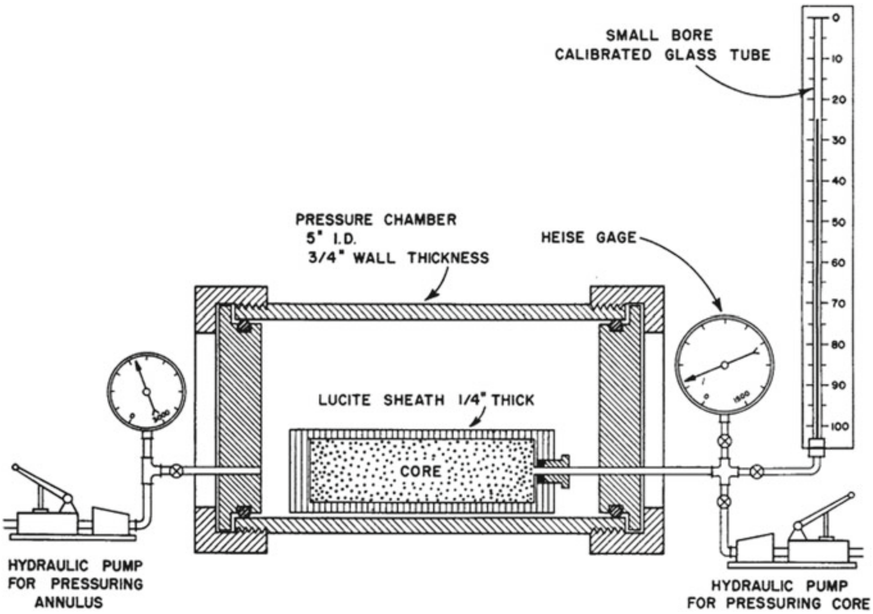

Fig. 7.4 Effective rock compressibility versus porosity. *Source* Hall (1953)

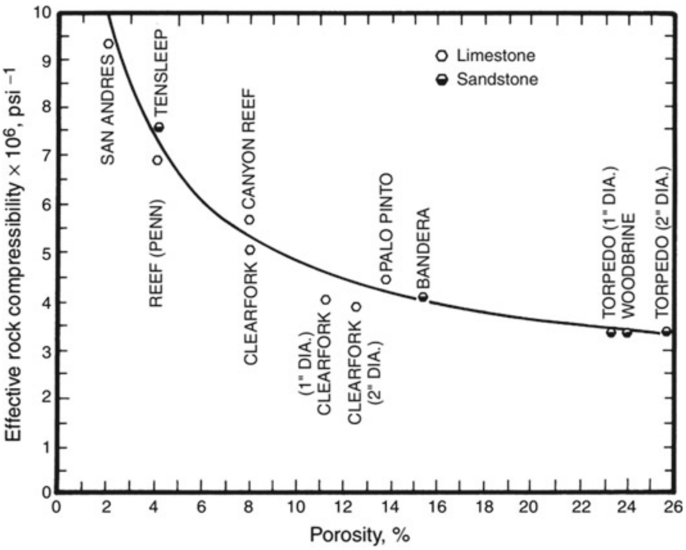

Fig. 7.5 Effective rock compressibility versus porosity. *Source* Hall (1953)

For limestone reservoir, Knapp (1959) noticed that both pore compressibility and porosity are related to the simple empirical formula. However, in a very detailed study, Newman (1973) proposed that any correlation between rock compressibility and porosity does not use to a big range of reservoir rocks.

7.2.1 Effects of Rock Compressibility on Field Development

Even though rocks may be appearing inflexible and incompressible when buried at high depth and are succumbed to high pressures they might deform. This activity is captured by compressibility, a parameter that may be obtained in particular labs. The reservoir Rock compressibility is considered as extra energy or drive mechanisms that support to extract fluids from the reservoir rock and compressibility can decrease the porosity and permeability of the reservoir. If fluids can not discharge out of the rock, an overpressured reservoir is formed. Therefore, Rock compression has both negative and positive impacts of hydrocarbon production. Compression process can make sand grains to be closer and this can decrease reservoir rock permeability. Consequently, this compaction can reduce the reservoir overall production. This effect is shown in Fig. 7.6.

Example 7.1
Calculate the hydrostatic pressure of 10.5 ppg mud in a well at depth 5000 ft?

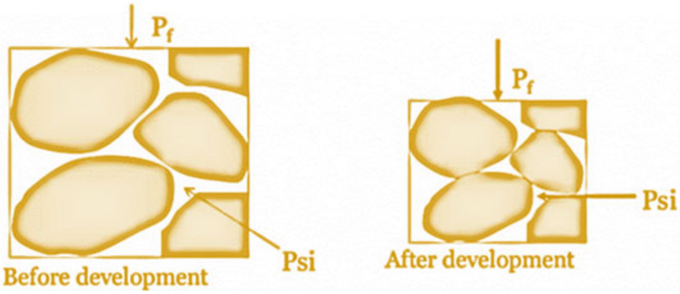

Fig. 7.6 Illustrates the compaction effects before and after development

Solution

$$P_{ov} = 0.052 \times \rho b \times D$$
$$= 0.052(10.5)(5000)2730\,\text{Psi}$$

Example 7.2
Calculate the hydrostatic pressure of 40° API oil in a well at depth 5000 ft?

Solution

$$\text{SG} = 141.5/(131.5 + 40) = 0.825$$

$$\text{Phyd} = 0.433(\text{SG})\text{h}$$
$$= 0.433(0.825)(5000) = 1786\,\text{Psi}$$

Example 7.3
Determine the normal reservoir pressure at depth 9000 ft if the Normal pore pressure gradient in the region is 0.422 psi/ft?

Solution P = 0.422 psi/9000 ft = 3978 Psi

Example 7.4
A formation has a pressure of 4000 Psi at reservoir depth of 7500 ft. The operator likes to use a safety allowance of 300 Psi opposite the formation, what is the required density of the mud?

Solution

$$P_{ov} = 0.052.\rho b.D$$

P = 4000 + 300/(0.052) (7500) = 11.0 ppg

Example 7.5
Utilize the below reservoir rock data to estimate the volume change in reservoir rock if the pressure dropped 100 psi only:

Porosity = 15%
Total reservoir area = 2,000,000 ft^2
Formation thickness = 150 ft
Reservoir rock compressibility = 3×10^{-6} 1/psi

Solution
Reservoir rock volume = 2,000,000 × 150 = 300×10^6 ft^2.
Pore volume (V_p) = reservoir rock volume × porosity
$V_p = 300 \times 10^6 \times 0.15 = 45 \times 10^6$ ft^3

$$\frac{dV_p}{dp} = C_f * V_p$$

$$\frac{dV_p}{dp} = 3 \times 10^{-6} * 45 * 10^6 = 135\,\mathrm{ft}^3/\mathrm{psi}$$

dp = 100 psi
dV_p = 13,500 ft^3
The percentage (%) change in reservoir pore volume @ 100 psi decline is:

$$\frac{dV_p}{dp} = \frac{13{,}500}{45 \times 10^6} = 0.03\%$$

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