1 Basic Pressure Concepts and Definitions

1.1 Introduction

Geopressure is the pressure beneath the surface of the earth. It is also known as the formation pressure. This could be lower than, equal to, or higher than the normal or hydrostatic pressure for a given depth. Hydrostatic or normal pressure is the force exerted per unit area by a column of freshwater from the earth's surface (e.g., sea level) to a given depth. Geopressures lower than the hydrostatic pressures are known as underpressures or subpressures, and they occur in areas where fluids have been drained, such as a depleted hydrocarbon reservoir. Geopressures higher than hydrostatic pressures are known as overpressured, and they occur worldwide in formations where fluids are trapped within sediments due to many geologic conditions and support the overlying load. Overpressured formations are also known as formations with abnormally high pore pressure. The lithostatic (or overburden) pressure at a given depth is due to the *combined* weight of the overlying rock and fluids. The fracture pressure is the pressure that causes the formation rock to crack. Figure 1.1 shows these concepts in graphical terms.

If the overlying fluid is composed of hydrocarbon as well as water (brine), the pressure versus depth plot will look like that shown in Figure 1.2.

The slope changes in the plot are due to density differences between brine, oil, and gas. The overpressure phenomenon is well known throughout the world. Among other things, the magnitude and distribution of overpressure in sedimentary basins have been known to critically impact the evolution of hydrocarbon provinces, control the migration of fluids within a basin, and affect the processes that are used to mine the subsurface resources, such as oil and gas. The most discussed and well-known cause of overpressure is the rapid burial of low-permeability water-filled sediments (e.g., clay) at a rate that does not allow the fluid to escape fast enough to maintain hydrostatic equilibrium upon further burial. Thus, further burial causes geopressure to rise even more. This is known as compaction disequilibrium. This is the leading cause of overpressure in most of the Tertiary clastic basins of the world, such as the Gulf of Mexico. This and many other mechanisms of overpressure are discussed in detail in Chapter 3.

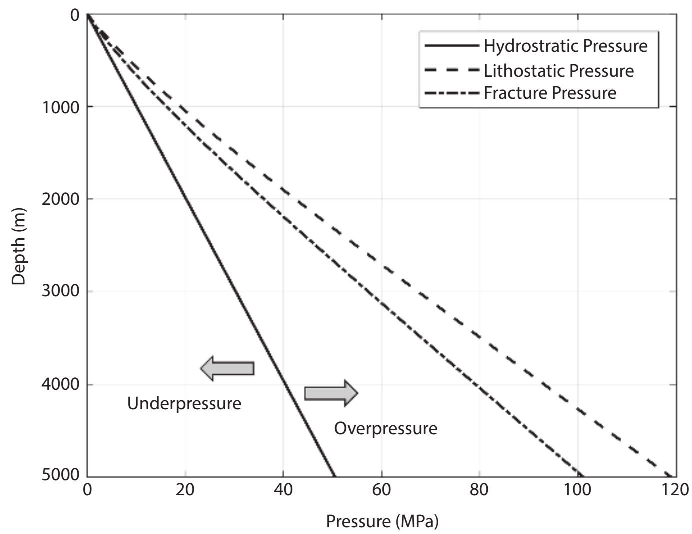

Figure 1.1 Pressure versus depth plot showing geopressure regimes.

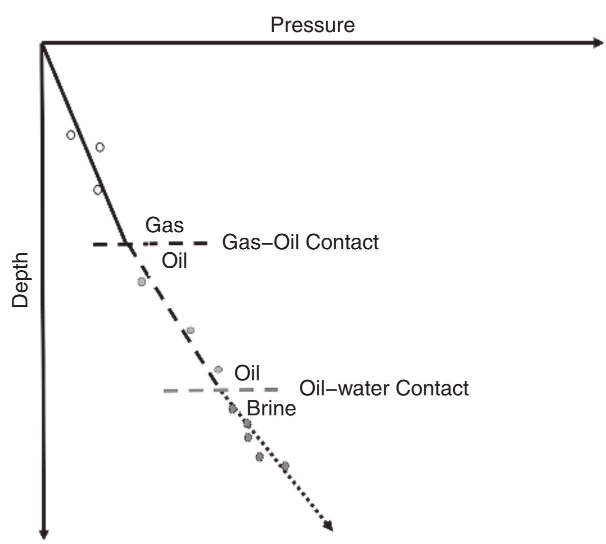

Figure 1.2 Pressure versus depth plot showing buoyancy effect due to hydrocarbons.

1.2 Basic Concepts

1.2.1 Units and Dimensions

Before we proceed, a word on units and dimensions is in order. All quantities in physics must either be dimensionless or have dimensions. All units can be expressed in terms of mass [M], length [L], and time [T]. In equations, the units must be consistent; there is no need for conversion factors. However, care is needed for quantities, such as pressure. It is force per unit area. The dimension of force is $[ML^{-1}T^{-2}]$; but if the unit of length is feet and the unit of pressure is pounds per square inch, or psi (as is commonly used in the US drilling community), a conversion factor is required, since these are inconsistent mixed units. In SI units, such conversion factors are not needed because all the units are consistent. The lack of inconsistency of units using the American system is known to have created a massive headache between the two drilling communities – those who use the SI units (some communities in Europe, for example) and those who do not use SI units. We shall discuss this further in this chapter in the context of pore pressure measurements.

As mentioned, pore pressure has the dimension of force per unit area. In the SI system, the unit of pressure is pascal (Pa), and in the British system, the unit is pounds per square inch (psi). We note that 1 Pa = 1.4504×10^{-4} psi. This is a rather small unit, and for most practical applications, it is customary to use either kilopascal (KPa) or megapascal (MPa). Drillers, engineers, and well loggers still use the British system, while the academicians prefer the SI system. Therefore, a fluency in both type of units is a must. We will be using the mixed system throughout the book. However, whenever possible, we will provide the SI or British system equivalents.

1.2.2 Hydrostatic Pressure

Sedimentary rocks in formations are composed of solid material and fluids in the porous network. Hydrostatic or normal pressure, P_h, is the pressure caused by the weight of a column of fluid and is given by

$$P_h = \int_0^z \rho_f(z) g dz + Pair \approx \rho_f g z + P_{air} \tag{1.1}$$

where z is the column height of the fluid, ρ_f is the density of the fluid, g is the acceleration due to gravity, and P_{air} denotes the pressure due to the atmosphere. The size and shape of the fluid column have no effect on hydrostatic pressure. The approximation on the right-hand side of equation (1.1) assumes that ρ_f is constant and z is the depth below sea level or the land surface. Hydrostatic pore pressure increases with depth; the gradient at a given depth is dictated by the fluid density at that depth. This is because the water or brine density is not constant. Water tends to expand with rising temperature but contracts with rising pressure. As we shall see later, between the two processes in the subsurface (i.e., increase in temperature and pressure), thermal expansion with increasing depth is greater than the mechanical compression. There are other factors that affect the water density, such as dissolved salt – the solubility of salt also increases with depth. Subsurface brines are more saline than the ocean water. This increase in total dissolved salt increases the density of water. The net effect is that the water (brine) density is a complex function of temperature, pressure, and total dissolved solids. If a subsurface formation is in the hydrostatic condition, it implies that there is an interconnected and open pore system from the earth's surface to the depth of measurement. To summarize, the fluid density depends on various factors, such as fluid type (oil, water, or gas), concentration of dissolved solids (i.e., salts and other minerals), and temperature and pressure of the fluid and gases dissolved in the fluid column. In Appendix A we provide some practical empirical relationships for physical properties of brine, gas, and oil needed for quantitative analysis of geopressure.

We strongly recommend that those who wish to pursue quantitative evaluation of geopressure use those equations for density and velocity of brine, gas, and oil ("dead" and "live") in a computer code. This will enable them to evaluate the true hydrostatic pressure as well as the pressure due to gas and oil columns of various heights. Here "dead" oil designates oil without any dissolved gas, whereas "live" oil means it contains dissolved gas.

What would a pressure versus depth plot such as the one in Figure 1.1 look like for a reservoir rock containing gas, oil, and water? An example is given in Figure 1.2 for the case of a reservoir filled with gas, oil, and water (brine). The slope changes are due to the density contrast between different kinds of fluids (gas, oil, brine), as discussed earlier. This kind of plot is very useful for determining the height of a hydrocarbon column in a reservoir. The discrete data points show actual measurements of pore pressure in a reservoir. Typically, not many measurements are carried out, as measurements are expensive in a real petroleum well; petroleum engineers make these discrete measurements and then look for slope changes to determine gas–oil and oil–water contacts, which yield the hydrocarbon column height. Eventually, seismic data are used along with geologic structure maps of a prospect to map these contacts in 3D. Volumetric calculations resulting from these measurements, along with uncertainty estimates, are used to determine the ultimate value of the asset.

1.2.3 Head

We introduce some terminology commonly used in fluid dynamics and relevant to geopressure. In the subsurface, fluids always move, although the speed at which they move is small in the human timescale. It is not so in the geologic timescale. The definitions that we gave in Section 1.2.2 are for fluids in the static condition. In fluid mechanics literature, the word *head* is commonly used. *Head* refers to a vertical dimension and has the dimension of length [L]. There are various types of heads.

A *pressure head* (also termed as *static pressure head* or *static head*) is the vertical elevation of the free surface of water above the point of interest. It is given by

$$\psi = P/\gamma = P/\rho g \tag{1.2}$$

where

ψ is the pressure head (length, typically in units of m)
P is the fluid pressure (force per unit area, typically in units of Pa)
γ is the specific weight (force per unit volume, typically in units of Newton/m^3)
ρ is the density of the fluid (mass per unit volume, typically in kg/m^3)

The term *hydraulic head* or *piezometric head* is used to specify a specific measurement of liquid pressure above a *datum.* It is composed of three terms: velocity head (h_v), elevation head ($z_{\text{elevation}}$), and pressure head (ψ). The following is referred to as the *head equation*:

$$C = h_v + z_{\text{elevation}} + \psi \tag{1.3}$$

Here C is a constant for the system (referred to as the *total head*) that appears in the context of the Bernoulli equation for incompressible fluids in hydrodynamics, which states that an increase in fluid speed occurs simultaneously with a decrease in pressure (Streeter, 1966). The *velocity head* (also referred to as *kinetic head*) is the head due to the energy of movement of the water. (In subsurface flow through porous rocks, this is negligible.) The *elevation head* is the elevation of the point of interest above a datum, usually sea level or the land surface.

1.3 Pore Pressure Gradient

A gradient is the first derivative of a physical quantity. The pressure gradient, dp/dz, is the *true* gradient of pore pressure, p, versus depth at a given point z. It shows change of pore pressure in a small scale. It is the rate at which pressure varies along a uniform column of fluid due to the fluid's own weight. Thus, a change in gradient implies a change in fluid density. Local gradients are most useful when working with the absolute pressure. However, the drilling community uses a term called *pore pressure gradient* to denote the density of fluid. It is the ratio of the pore pressure (p at a depth z) to the depth z. This is usually expressed in pounds per square inch per foot (abbreviated by psi/ft) in the British system of units and MPa/m in the SI system. It is clear that this gradient is *datum* dependent. Furthermore, pore pressure gradient is *not the true gradient* of p as a geoscientist or an engineer would define. It is simply pressure/depth. The conversion between fluid density and fluid pressure gradient is

$$\begin{gathered} 1 \text{ psi/ft} = 2.31 \text{ g/cm}^3 \\ \text{Thus } 1 \text{ psi/ft} = 2.31 \text{ g/cm}^3 = 0.0225 \text{ MPa/m} = 22.5 \text{ kPa/m} \end{gathered} \tag{1.4}$$

Thus, the fluid density, can be defined as

$$\text{fluid density (g/cm}^3) = 0.433 \text{ (psi/ft)} \tag{1.5}$$

The drilling community uses a term called *equivalent mud weight* (EMW) to denote the density of fluid (mud) required to drill a well. It is expressed in pounds per gallon, abbreviated as ppg. A conversion factor for equivalent mud weights is

$$1 \text{ lb/gal or } 1 \text{ ppg} = 0.0519 \text{ psi/ft} \tag{1.6}$$

Weight in itself is not a gradient. If we relate weight to a volume, however, we have density, and density does convert to a gradient. When we refer to mud weights as 10 pounds, we mean the mud *density* is 10.0 lb/gal or ppg. This is a density. (In this nomenclature, pure water density would be 8.344 ppg.) Fertl (1976) suggested the following relation for hydrostatic pressure in psi, as is commonly used in drilling operations:

$$P_h = CM_w z \tag{1.7}$$

where z is the vertical height of fluid column in feet, M_w is fluid density for mud weight expressed in lb/gal (or ppg) or pounds per cubic feet (lb/ft^3), and C is a conversion constant equal to 0.0519 if M_w is expressed in pounds per US gallon and 0.00695 if M_w is expressed in lb/ft^3. The conversion factor 0.0519 (inverse of 19.250) is derived from dimensional analysis as follows:

$$\frac{1\text{psi}}{\text{ft}} = \frac{1\,\text{ft}}{12\text{in}} \times \frac{1\text{lb/in}^2}{1\text{psi}} \times \frac{231\text{in}^3}{1\text{USgal}} = 19.250\text{lb/gal} \tag{1.8}$$

It would be more accurate to divide a value in lb/gal by 19.25 than to multiply that value by 0.052. The magnitude of the error caused by multiplying by 0.052 is approximately 0.1 percent. Let us take an example: for a column of freshwater of 8.33 pounds per gallon (lb/US gal or ppg) standing still hydrostatically in a 21,000 ft vertically cased wellbore from top to bottom (vertical hole), the pressure gradient would be

$$\text{Pressure gradient} = 8.33/19.25 = 0.43273 \text{ psi/ft} \tag{1.9}$$

and the hydrostatic *bottom hole pressure* (BHP) is then BHP = true vertical depth × pressure gradient = 21,000 (ft) × 0.43273 (psi/ft) = 9087 psi. However, the formation fluid pressure (pore pressure) is usually much greater than the pressure due to a column of freshwater, and it can be as much as 19 or 20 ppg. For an onshore vertical wellbore with an exposed open hole interval at 21,000 ft with a pore pressure gradient of 19 ppg (or 19 × 0.0519 (psi/ft)), the BHP would be BHP = pressure gradient × true vertical depth = 19.0 × 0.0519 (psi/ft) × 21,000 (ft) = 20,708 psi. (It would be 20,727 psi if we replace 0.0519 by 1/19.25.) The calculation of a bottom hole pressure and the pressure induced by a static column of fluid (drilling mud) are the most important and basic calculations in the petroleum industry. In summary, pore pressure gradient is a *dimensional* term used by drilling engineers and mud engineers during the design of drilling programs for drilling (constructing) of oil and gas wells into the earth. In Table 1.1 we give some useful conversion factors.

In the Gulf Coast of the United States, a fluid pressure gradient of 0.465 psi/ft is considered to be normal or hydrostatic; it corresponds to a salt concentration of 80,000 ppm and a temperature of 77°F. However, the hydrostatic pressure gradient is variable depending upon the temperature, pressure, and salinity, as noted earlier. An increase in salt concentration at a given temperature and pressure would increase the hydrostatic gradient. Dissolved gas in water, for example, methane, also affects the density of water – it lowers the density – and hence the hydrostatic gradient will be lower. We

Table 1.1 Units and conversions

Psi	= 0.070307 kg. force/cm^2
Atm	= 1.033 kg force/ cm^2
Atm	= 14.6959 psi
Psi	= 0.006895 MPa
Psi/ft	= 2.31g/cm3
	= 1 4 4 lb / ft^3
	= 19.25 lb/gallons or ppg
1 Pa = 1N/m^2 = 1.4504 x 10^{-4} psi	
1 Mpa = 10^6 Pa = 145.0378 psi	
1 Mpa = 10 bars	
1 N = 1 kg. m/s^2	
1 kbar = 100 MPa	
1 psi / ft. = 2.31 g/cm^3	
$\approx 0.0225 MPa/m = 22.5 kPa/m$	

note that the solubility of methane in water is a function of salt concentration at a given temperature and pressure – it increases with increasing salt concentration. Thus, dissolved gases would cause the hydrostatic gradient to be lower. In the vicinity of salt domes, salt concentration could be markedly higher, leading to a higher hydrostatic gradient. In Table 1.2 we show typical values for density and pressure gradients for oil, brine, and some drilling fluids. In Table 1.3 we show typical hydrostatic pressure gradients for several areas of active drilling.

It is clear from these discussions that hydrostatic (or normal) pressure for a static water column of height z is equivalent to a water-saturated porous medium such as clean sandstone of the same height with the assumption that the sandstone consists of interconnected pores. Formation pressure (or geopressure) that *differs* from hydrostatic pressure is defined as *abnormal pressure.* Formation pressure (or geopressure) *exceeding* hydrostatic pressure is defined as *overpressure*, whereas formation pressure *lower* than hydrostatic is defined as *subpressure*. Therefore, we emphasize that before embarking on any computation involving determination of subsurface pore pressure, we must establish a proper baseline – deciding on the "accurate" hydrostatic pressure gradient with as much accuracy as possible.

1.4 Overburden Stress

The *overburden* or *lithostatic stress*, S, at any depth, z, is the stress that results from the *combined* vertical weight of the rock matrix and the fluids in the pore space overlying the formation of interest as well as the weight of the static water column, if in an offshore environment, and the atmospheric air pressure. This can be expressed as

$$S = P_{\text{air}} + g\int_0^{z_w} \rho_{sw}(z)dz + g\int_{z_w}^{z} \rho_b(z)dz \tag{1.10}$$

Table 1.2 Fluid densities and corresponding pressure gradients

Fluid	Total solids (ppm)	Density (g/ml)	Fluid pressure gradient (psi/ft)	(kPa/m)
Freshwater	0	1.0	0.433	9.8
Brine	28,000	1.02	0.441	10.0
	55,000	1.04	0.450	10.2
	84,000	1.06	0.459	10.4
	113,000	1.08	0.467	10.6
	144,000	1.10	0.476	10.8
	176,000	1.12	0.485	11.0
	210,000	1.14	0.493	11.2
Oil	API° (60°F)			
	70.6	0.70	0.303	6.90
	45.40	0.80	0.346	7.80
	25.70	0.90	0.390	8.80
	10.00	1.00	0.433	9.80
Drilling mud	lb/gal or ppg			
	8.35	1.00	0.433	9.80
	10.02	1.20	0.520	11.8
	11.69	1.40	0.607	13.70
	13.36	1.60	0.693	15.70
	15.03	1.80	0.780	17.70
	16.70	2.00	0.867	19.60
	18.37	2.20	0.953	21.60
	20.04	2.40	1.040	23.50
	21.71	2.60	1.126	25.50
	23.38	2.80	1.213	27.50
	25.05	3.00	1.300	29.40

Note: Pressure gradients are related to the specific gravity (γ) rather than the density (ρ), where $\gamma = \rho g$, g = 9.81 m/s^2.
Source: Modified after Gretener (1981)

Table 1.3 Normal pore pressure gradients for several areas

Area	Pressure gradient (psi/ft)	Pressure gradient (g/cc)
West Texas	0.433	1.000
Gulf of Mexico (coastline)	0.465	1.074
North Sea	0.452	1.044
Malaysia	0.442	1.021
Mackenzie Delta	0.442	1.021
West Africa	0.442	1.021
Anadarko Basin	0.433	1.000
Rocky Mountains	0.436	1.007
California	0.436	1.014

where P_{air} is the pressure due to the atmospheric air column (typically 14.5 psi or 1 bar), ρ_b is the bulk density, ρ_{sw} is the sea water density (both depend on depth), z_w is depth to the ocean bottom, and g is the acceleration due to gravity. The bulk density of a fluid-saturated rock is given by

$$\rho_b = (1 - \phi)\rho_r + \phi\, \rho_f \tag{1.11}$$

where ϕ is the fractional porosity (the void space in the rock), ρ_{f} is the pore fluid density, and ρ_r is the density of the matrix (grain density). It should be noted that the overburden stress computation in the context of drilling wells should always account for the air gap or the atmospheric pressure. Although this is small, it could be significant while dealing with overburden stress in shallow formations, such as pressured aquifer sands or methane hydrates, as discussed later. Overburden stress is *depth dependent* and increases with depth in a nonlinear fashion. In some of the older literature on geopressure, a default value of 1.0 psi/ft for overburden stress gradient (overburden stress divided by depth) has been recommended for the "average" Tertiary deposits off the Texas–Louisiana coast. This corresponds to a force exerted by a formation with an *average* bulk density of 2.31 g/cm^3. However, this is not true in reality, where we always deal with rocks of variable bulk densities. At shallower depths, the overburden gradient would be less than 1.0 psi/ft, while at deeper depths, it could be larger than 1.0 psi/ft. In Figure 1.3 we show typical overburden gradients from selected basins.

1.5 Effective Vertical Stress and Terzaghi's Law

When a rock is subjected to an external stress, it is opposed by the fluid pressure of pores in the rock. This is due to Newton's law of classical mechanics. More explicitly, if P is the formation or pore fluid pressure at a depth where the vertical component of the total stress (namely, the vertical overburden stress) on it is S, then the vertical effective stress σ is defined as (see Figure 1.4)

$$\sigma = S - P \tag{1.12}$$

This is known as the Terzaghi's principle or law (Terzaghi, 1923). This principle was invoked to describe the consolidation of soil in the context of geotechnical engineering (soil consolidation) (see Chapter 2). Compaction is due to the vertical effective stress – it is the stress that is transmitted through the solid framework. This (vertical effective stress) is a very important parameter to describe geopressure phenomenon quantitatively, especially when geophysical methods such as seismic or sonic logs are used to quantify geopressure. A relationship between velocity and overpressure is intuitively expected, since acoustic velocity and vertical effective stress are related closely. This will be discussed in Chapter 3. We note that

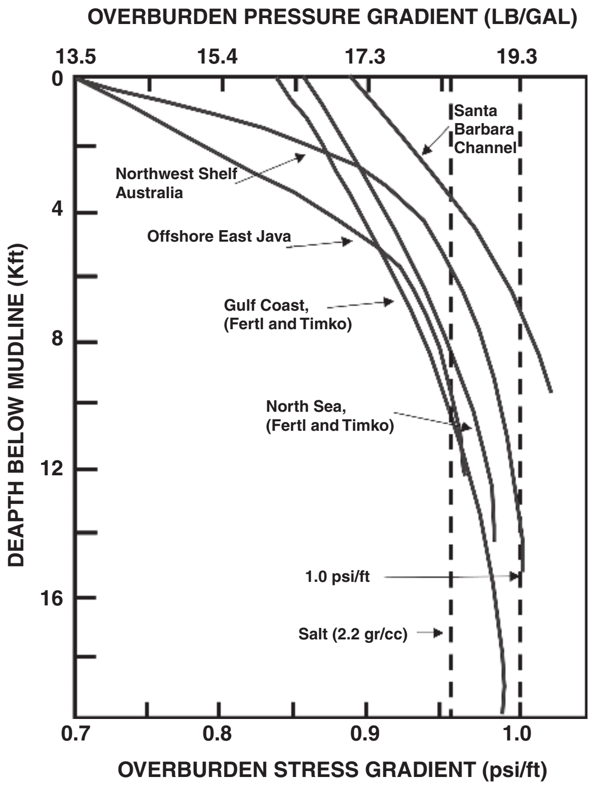

Figure 1.3 Typical overburden stress gradients versus depth in psi/ft and ppg. Modified after Dutta (1987a).

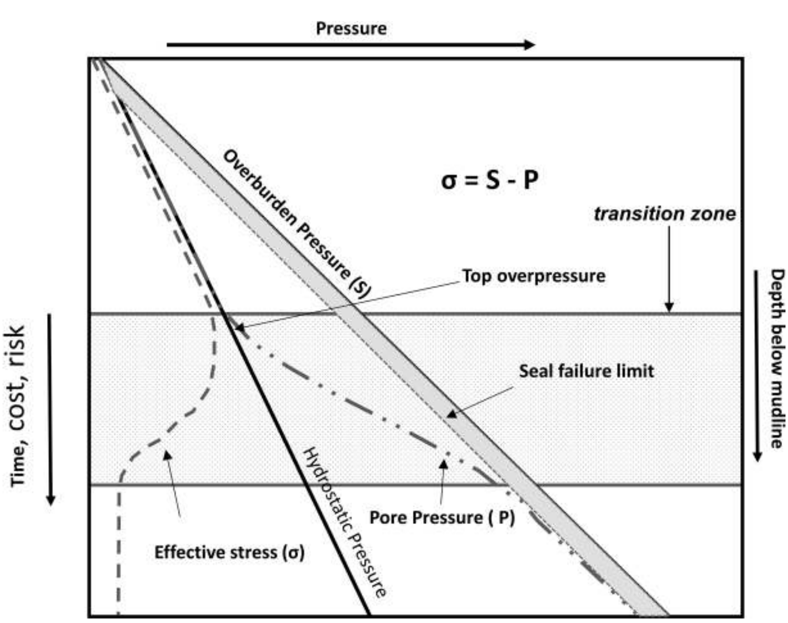

Figure 1.4 Subsurface pressure environment and some commonly used definitions. Modified after Dutta (1987a).