1.1.2 Crude Oil Properties

Petroleum (an equivalent term is crude oil) is a complex mixture consisting predominantly of hydrocarbons and containing sulfur, nitrogen, oxygen, and helium as minor constituents. The physical and chemical properties of crude oils vary considerably and depend on the concentration of the various types of hydrocarbons and minor constituents present.

An accurate description of physical properties of crude oils is of a considerable importance in the fields of both applied and theoretical science and especially in the solution of petroleum reservoir engineering problems. Physical properties of primary interest in petroleum engineering studies include:

- Crude oil gravity "γo".
- Specific gravity of solution gas "γg".
- Crude oil density "ρo".
- Gas solubility "Rs".
- Bubble point pressure "pb".
- Oil formation volume factor "Bo".
- Isothermal compressibility coefficient of crude oil "co".
- Total formation volume factor "Bt".
- Crude oil viscosity.

1 Crude Oil API Gravity "γo".

The specific gravity of a crude oil is defined as the ratio of the density of the oil to that of water.

$$\gamma_o = \frac{\rho_o}{\rho_w} \qquad eq.(1.29)$$

شرط ان تقاس الكثافتين عند نفس درجة الحرارة

where:

γo = specific gravity of the oil.

ρo = density of the crude oil, lb/ft3.

ρw = density of the water, 62.4 lb/ft3.

ρw = 8.33 ppg

$$\gamma_o = \frac{\rho_o}{62.4}, 60^\circ/60^\circ$$

$$API = \frac{141.5}{\gamma_o} - 131.5 \qquad eq.(1.30)$$

في الصناعة النفطية ال API يعتبر مؤشر للكثافة

2 Specific Gravity of the Solution Gas, "γg"

The specific gravity of the solution gas γg is described by the weighted average of the specific gravities of the separated gas from each separator. This weighted average approach is based on the separator gas-oil ratio, or:

$$\gamma_g = \frac{\sum_{i=1}^{n} (R_{sep})_i (\gamma_{sep})_i + R_{st}\gamma_{st}}{\sum_{i=1}^{n} (R_{sep})_i + R_{st}} \qquad eq.(1.31)$$

where:
n = number of separators.
Rsep = separator GOR, scf/STB.
γsep = separator gas gravity.
Rst = GOR from the stock-tank, scf/STB.
γst = gas gravity from the stock-tank.

3 Crude Oil Density, "ρo"

The crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot. Several empirical correlations for calculating the density of liquids of unknown compositional analysis have been proposed.
The following equation used to calculate the density of the oil at pressure below or equal to the bubble–point pressure. Solving Equation for the oil density gives:

من المفروض ان تقاس بواسطة PVT وتتراوح بين
lb/ft3 for light volatile oil to 60 lb/ft3 for heavy crude oil with little 30 or no gas solubility

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{Bo}$$

Where:

γo = specific gravity of the stock–tank oil
Rs = gas solubility, scf/STB
ρo =oil density, lb/ft3

Depending on Standing (1981), the density of a crude oil at a specified pressure and temperature can be calculated from the following expression:

$$\rho_o = \frac{62.4\gamma_o + 0.0136 R_s \gamma_g}{0.9759 + 0.000120\left[R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25(T-460)\right]^{1.2}} \qquad eq.(1.32)$$

Where:

T = system temperature, °R.
γg = specific gravity of the gas.
Rs = gas solubility, scf/STB.
Bo=oil formation volume factor, bbl/STB

4 Gas Solubility "*Rs*"
(solution gas oil ratio or dissolved gas –oil ratio)
كمية الغاز المتحرر من النفط عندما ينتج النفط من المكمن الى الظروف السطحية

$$Rs = \frac{vol.\ of\ gas\ produced\ at\ surface\ con.}{vol.\ of\ oil\ entering\ stock\ tank\ at\ surface\ con.}$$

Rs=SCF/STB

The gas solubility Rs is defined as the number of standard cubic feet of gas that will dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. For a particular gas and crude oil to exist at a constant temperature, the solubility increases with pressure until the saturation pressure is reached. At the saturation pressure (bubble-point pressure) all the available gases are dissolved in the oil and the gas solubility reaches its maximum value. As the pressure is reduced from the initial reservoir pressure pi, to the bubble-point pressure pi, no gas evolves from the oil and consequently the gas solubility remains constant at its maximum value of Rsb. Below the bubble-point pressure, the solution gas is liberated and the value of Rs decreases with pressure.

As shown in Figure (1.1)

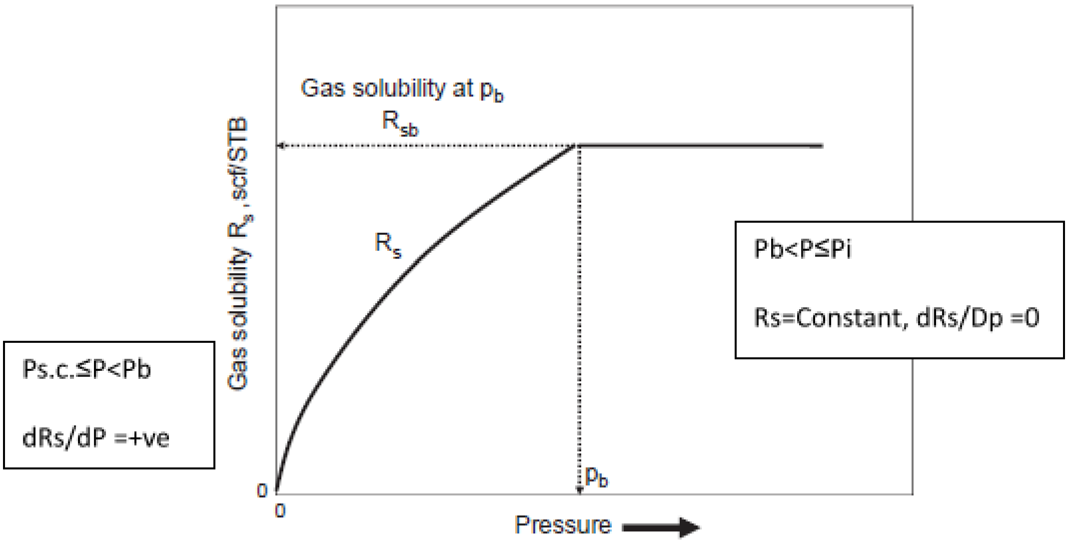


Figure (1.1):Gas-Solubility as a function of pressure relationship

- **dRso/dp =Gas Solubility Gradient [(SCF/STB)/psi]**

هناك نوع اخر من الذوبانية يسمى نسبة الغاز الى النفط التراكمية (Rp)

Rp= Cumulative Produced Gas-Oil Ratio (Rp)=GOR

$$\mathbf{Rp}=\frac{Gp}{Np}$$

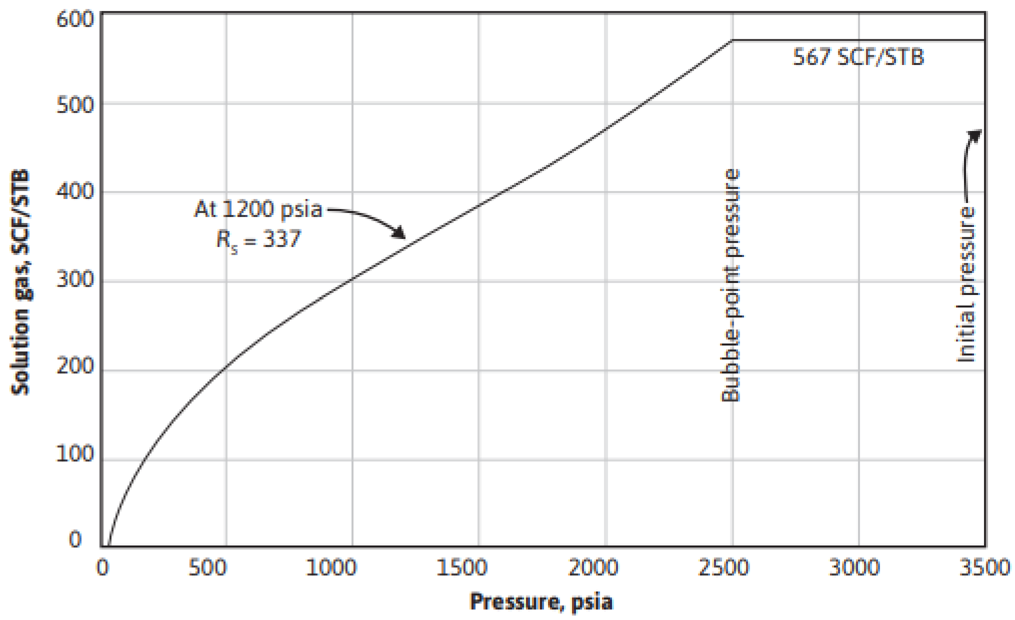
Rso= solution gas-oil ratio (SCF/STB)
Gp=Cumulative oil Production (SCF)
Np=Cumulative Oil Production (STB)

من الافضل تشغيل المكمن عند Rp=Rsi ذلك لان الغاز هو احد الطاقات المساهمة في الانتاج.
احد الحلول المقترحة لخفض ال Rp هي اعادة جزء من الغاز الى المكمن او غلق الابار التي تنتج بمعدلات غاز الى نفط عالية او تغيير مناطق التثقيب.,

Figure in below shows the variation of solution gas with pressure for the Big Sandy reservoir fluid at reservoir temperature 160°F.
Pi= 3500 psia,
solution gas 567 SCF/STB
Pb=2500 psia
At 1200 psia, the solution gas is 337 SCF/STB,

The data of Figure were obtained from a laboratory PVT study of a bottom-hole sample.

$$\text{Average solubility} = \frac{567 - 337}{2500 - 1200} = 0.177 \text{ SCF/STB/psi}$$



Standing's Correlation for Determining "*Rs*"

$$R_s = \gamma_g \left[\left(\frac{p}{18.2} + 1.4 \right) 10^x \right]^{1.2048} \qquad eq. (1.33)$$

with:

$$x = 0.0125 API - 0.00091 (T - 460) \qquad eq. (1.34)$$

where:
Rs = gas solubility, scf/STB. T = temperature, °R.
p = system pressure, psia.
γg = solution gas specific gravity. API = oil gravity, °API.

5 Bubble Point Pressure "p_b"

The bubble-point pressure Pb of a hydrocarbon system is defined as the highest pressure at which a bubble of gas is first liberated from the oil. the bubble-point pressure is a strong function of gas solubility Rs, gas gravity γg, oil gravity API, and temperature T, or:

$$pb=f(R_s,\gamma_g,API,T)$$

6 Oil Formation Volume Factor "B_o"

The oil formation volume factor, Bo, is defined as the ratio of the volume of oil (plus the gas in solution) at the prevailing reservoir temperature and pressure to the volume of oil at standard conditions. Bo is always greater than or equal to unity.

$$Bo=f(Rs,\gamma g,\gamma o,T)$$

حجم النفط في المكمن هو اكبر من حجمه في الخزان
وذلك للأسباب التالية
1. تحرر الغاز عند هبوط الضغط
2. على الرغم من ان هبوط الضغط يؤدي الى تمدد الطور السائل الا ان انخفاض درجة الحرارة يعادل التمدد الحاصل جراء انخفاض الضغط.
اذن معامل التكوين الحجمي يعبر عنه رياضيا بالصيغة التالية

$$\mathbf{Bo}=\frac{vol.\ of\ oil+vol.\ of\ dissolved\ gas\ at\ res.\ con.}{vol.\ of\ oil\ at\ stock\ tank\ at\ s.c.}$$

Bo>1

اذا كانت قيمة Bo تساوي واحد اذن النفط هو من نوع الdead oil

مقلوب الBo يسمى معامل الانكماش Shrinkage factor, bo

$$\frac{1}{Bo}\mathbf{Bo=}\quad \frac{STB}{bbl}\mathbf{=1>}$$

$$B_o=\frac{(V_o)_{p,T}}{(V_o)_{sc}} \qquad eq.(1.37)$$

where:

Bo = oil formation volume factor OFVF, bbl/STB.

(Vo)p,T = volume of oil, in bbl, under reservoir pressure, p, and tempera-ture, T.
(Vo)sc = volume of oil is measured under SC, STB.
A typical oil formation factor curve as shown in Figure below.

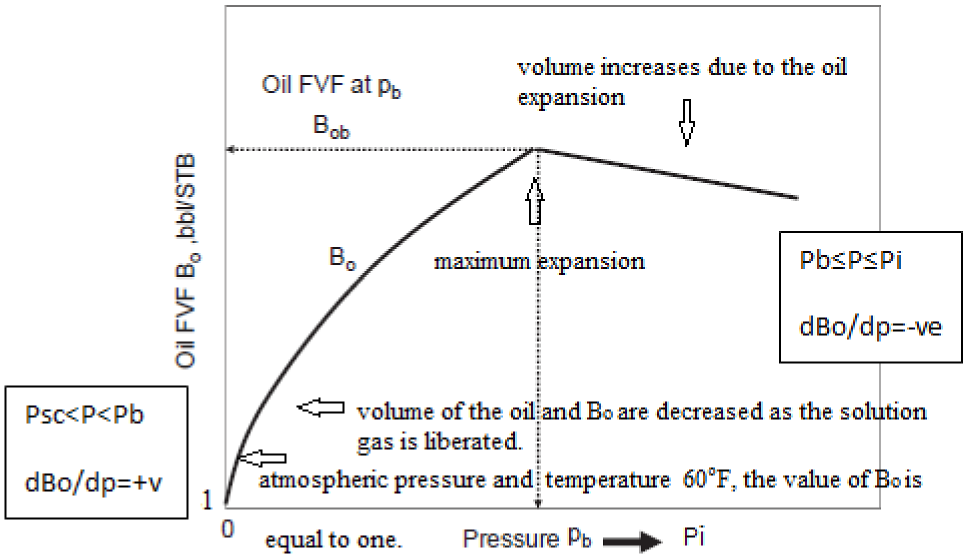


Figure shows Oil Formation Volume Factor “FVF” as a function of pressure relationship.

7 Isothermal Compressibility Coefficient of Crude Oil "*co*"
Isothermal compressibility coefficients are required in solving many reservoir engineering problems, including transient fluid flow problems, and they are also required in the determination of the physical properties of the undersaturated crude oil.

ملاحظة مهمة تقاس هذه الخاصية عندما يكون الضغط هو اعلى من ضغط نقطة الفقاعة bubble point pressure

$$c = -\frac{1}{V}\left(\frac{\partial V}{\partial p}\right)_T$$

$$c_o = -(1/V)(\partial V/\partial p)_T$$

$$c_o = -\frac{1}{V}\left(\frac{V_1 - V_2}{p_1 - p_2}\right)_T$$

V هنا عادة نأخذها القيمة الاقل وعليه فأن V_2 ستكون نفس V (اي الاقل نفسها)
بصيغة اخرى

$$Co = -\frac{1}{V} \times \frac{dv}{dp}$$

$$Co \times dp = -\frac{dv}{v}$$

$$Co\,(p_1 - p_2) = -\ln\left(\frac{v2}{v1}\right)$$

$$v_2 = v_1 \times e^{Co(p1-p2)}$$

$$v_2 = v_1 \times [1 + Co\,(p_1 - p_2)]$$

$$p > p_b$$

$$c_o = -(1/B_o)(\partial B_o/\partial p)_T$$

$$c_o = -\frac{1}{Bo}\left(\frac{\partial Bo}{\partial p}\right)_T$$

$$c_o = -(1/\rho_o)(\partial \rho_o/\partial p)_T$$

$$c_o = -\frac{1}{\rho_o}\left(\frac{\partial \rho_o}{\partial p}\right)_T$$

$$\rho_o=\rho_{ob}\times [1+Co\ (p-p_b)]$$

$$B_o=B_{ob}\times [1+Co\ (p-p_b)]$$

$$p>p_b$$

Where:

co = isothermal compressibility, psi–1

ρo = oil density lb/ft3

Bo = oil formation volume factor, bbl/STB

At pressures below the bubble–point pressure, the oil compressibility is defined as:

اما في حالة كون الضغط اقل من نقطة الفقاعة اذن

$$c_o = \frac{-1}{B_o}\frac{\partial B_o}{\partial p} + \frac{B_g}{B_o}\frac{\partial R_s}{\partial p}$$

Where

Bg = gas formation volume factor, bbl/scf

Rs = gas solubility at any pressure, scf/STB

8 Total Formation Volume Factor "*Bt*"

Bt, is defined as the ratio of the total volume of the hydrocarbon mixture (i.e., oil and gas, if present), at the prevailing pressure and temperature per unit volume of the stock-tank oil.

Total Formation Volume Factor describe the pressure-volume relationship of hydrocarbon systems <u>below their bubble-point pressure</u>.

$$B_t = \frac{(V_o)_{p,T} + (V_g)_{p,T}}{(V_o)_{sc}} \qquad eq.(1.41)$$

$(V_g)_{p,T}$ = 0 above the bubble point pressure; no free gas exists.

$$B_o = \frac{(V_o)_{p,T}}{(V_o)_{sc}}$$

where:
Bt = total FVF, bbl/STB.
(Vo)p,T = volume of the oil at p and T, bbl.
(Vg)p,T = volume of the liberated gas at p and T, bbl.
(Vo)sc = volume of the oil at SC, STB.

$$B_t = B_o + (R_{sb} - R_s)B_g \qquad eq.(1.42)$$

where:
Rsb = gas solubility at the bubble point pressure, scf/STB.
Rs = gas solubility at any pressure, scf/STB.
Bo = oil FVF at any pressure, bbl/STB.
Bg = gas FVF, bbl/scf.
A typical plot of Bt as a function of pressure for an undersaturated crude oil as shown in Figure below.

$$B_t = \frac{(V_o)_{p,T} + (V_g)_{p,T}}{(V_o)_{sc}}$$

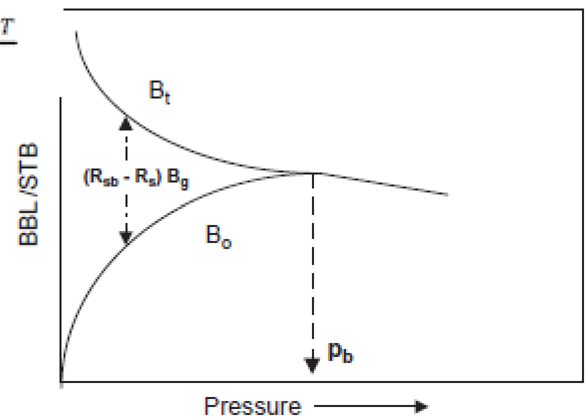


Figure shows Bo and Bt vs. pressure.

9 Crude Oil Viscosity "μ_o"

The viscosity, in general, is defined as the internal resistance of the fluid to flow. μ_o is an important physical property that controls and influences the flow of oil through porous media and pipes.

According to the pressure, the viscosity of crude oils can be classified **into three categories**:

- Dead-Oil Viscosity.
- Saturated-Oil Viscosity.
- Undersaturated-Oil Viscosity.

لزوجة النفط تعتمد على

1. مقدار الذوبانية (Rs)
2. قيمة ال API
3. الحرارة والضغط

بشكل عام تتناسب اللزوجة طرديا مع الضغط وعكسيا مع درجة الحرارة

$$\mu_o \propto \frac{P}{T}$$

The viscosity of the oil is measured laboratory by (High Pressure High Temperature Rolling Ball Viscometer).

viscosity is dimensionally represented as $[M^1 L^{-1} T^{-1}]$.

PETROLEUM RESERVOIRS

Oil and gas accumulations are result from the coincident occurrence of the following six elements:

1. Source Rock
2. Burial depth and temperature
3. Reservoir Rock
4. Migration pathways
5. Seal Rock
6. Trap

Petroleum will accumulate in traps, which are locations where oil and gas can no longer migrate to the surface. The two primary types of traps are structural and stratigraphic. **A structural trap** is present when the geometry of the reservoir prevents fluid movement. Structural traps)comprising about 70%(occur where the reservoir beds are folded and perhaps faulted into shapes that can contain commercially valuable fluids like oil and gas. Anticlines are a common type of structural trap. Folding and faulting can be caused by tectonic or regional activity.

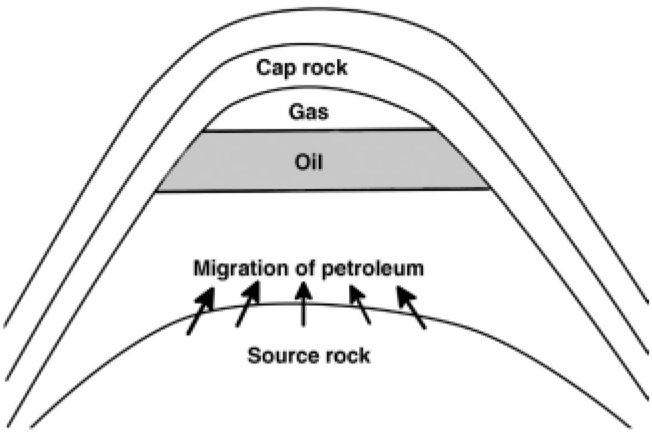
Stratigraphic traps)comprising about 25%(occur where the fluid flow path is blocked by changes in the formation's character.

Stratigraphic traps originate from facies change or geologic unconformity that provides a barrier to flow and leads to the entrapment of petroleum.

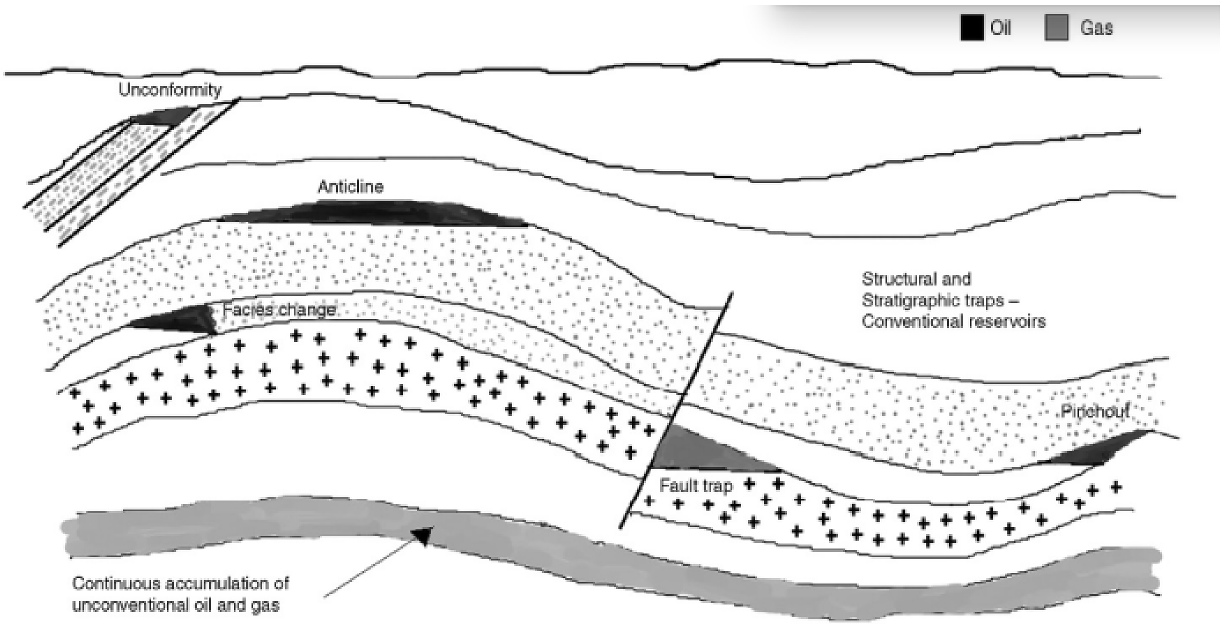
The types of stratigraphic traps include sand thinning out or porosity reduction because of diagenetic changes.

Diagenesis refers to processes in which the lithology of a formation is altered at relatively low pressures and temperatures.

In addition to structural and stratigraphic traps, many traps are formed by a combination of structural and stratigraphic features and are called **combination traps.**



Vertical migration and accumulation of petroleum in conventional reservoirs



Depiction of structural and stratigraphic traps responsible for oil and gas accumulation in conventional reservoirs.

RESERVOIR ROCKS

Oil and gas reservoir rocks are porous and permeable (They contain interconnected passageways of microscopic pores or holes that occupy the areas between the mineral grains of the rock).

Typical reservoir rocks have a microscopic network of pores where reservoir fluids are stored.

Shale is the most abundant rock type in sedimentary basins, comprising about 80% or more of the total rock volume in many instances. However, conventional oil and gas reservoirs are mostly composed of sandstone and carbonate formations, often interbedded with shale. Carbonate reservoirs (limestone or dolomite) are highly prolific producers, about 60% of the world's production of petroleum is based on these reservoirs. Sandstone reservoirs account for over 30% of production.

The reserves

The term "reserves" means different things to different subjects. To the oil and gas industry, reserves are the amount of crude oil, natural gas, and associated substances that can be produced profitably in the future from subsurface reservoirs.

Oil Reservoirs

Depending upon initial reservoir pressure pi

, oil reservoirs can be subclassified into the following categories:

1. Undersaturated oil reservoir. If the initial reservoir pressure pi is greater than the bubble-point pressure pb of the reservoir fluid, the reservoir is labeled an under saturated oil reservoir.

2. Saturated oil reservoir. When the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid, the reservoir is called a saturated oil reservoir.

3. Gas-cap reservoir. If the initial reservoir pressure is below the bubblepoint pressure of the reservoir fluid, the reservoir is termed a gas-cap or two-phase reservoir.

Basic concepts and definitions in Reservoir Engineering

Porosity Ø

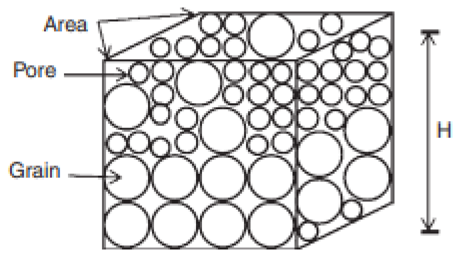
From the reservoir-engineering standpoint, one of the most important rock properties is porosity

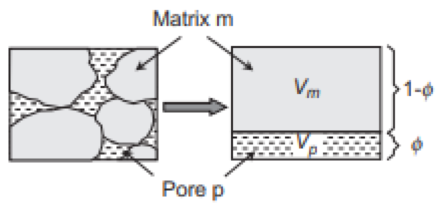
Porosity is defined as a measure of the capacity of reservoir rocks to contain or store fluids.

ان كانت الحبيبات grains متماثلة الحجوم يطلق عليها very well sorted وعليه

Maximum porosity والعكس بالعكس

poor sorted يعطي minimum porosity .





Or

Porosity is defined as the ratio of the void space in a rock to the bulk volume of the rock multiplied by 100% to express in per cent.

Three kinds of pores are normally found in materials (Figure below).

1. The closed pores are not accessible.

2. The blind pores terminate within the material.

3. The through pores permit fluid flow through the material.

The following table defines what typically constitutes poor, good, and very good porosity.

Range of Porosity and Practical Cutoff

What is good porosity
• 0–5%—Negligible • 5–10%—Poor • 10–15%—Fair • 15–20%—Good • >20%Very good • Practical cutoff for oil sandstone ~8% • Cut off for limestone ~5% • For gas reservoirs, the cutoff is lower

هناك صخور تعتبر porous ولكن impermeable مثل الصخور النارية و الsalt شرط عدم مساسها الماء وكذلك ال shale هو مسامي ولكن غير نفاذ.

سؤال: ولكن بعض المكامن هي من نوع صخور الطفل shale و هي منتجة؟

Porosity values depend on rock type, as illustrated in Table below. The two basic techniques for directly measuring porosity are core analysis in the laboratory and well logging. Laboratory measurements tend to be more accurate, but they sample only a small fraction of the reservoir.

The Dependence of Porosity on Rock Type

Rock Type	Porosity Range (%)	Typical Porosity (%)
Sandstone	15–35	25
Unconsolidated sandstone	20–35	30
Carbonate		
Intercrystalline limestone	5–20	15
Oolitic limestone	20–35	25
Dolomite	10–25	20

$$\phi = \frac{V_b - V_{gr}}{V_b} = \frac{V_p}{V_b}$$

where

φ = porosity, fraction

Vb = bulk volume of the reservoir rock

Vgr = grain volume

Vp = pore volume

ENGINEERING CLASSIFICATION OF POROSITY

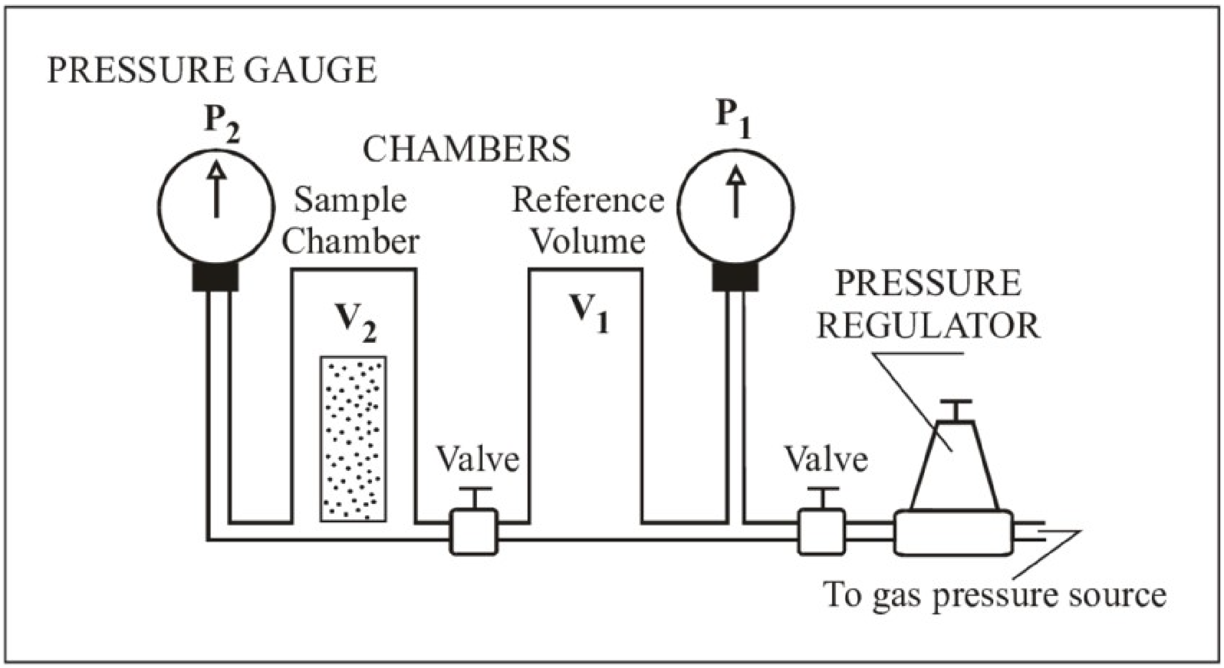
1. total (absolute)
2. effective.

GEOLOGICAL CLASSIFICATION OF POROSITY

1. (primary or matrix porosity)
2. (secondary or induced porosity).

Boyle’s Law Porosimeter

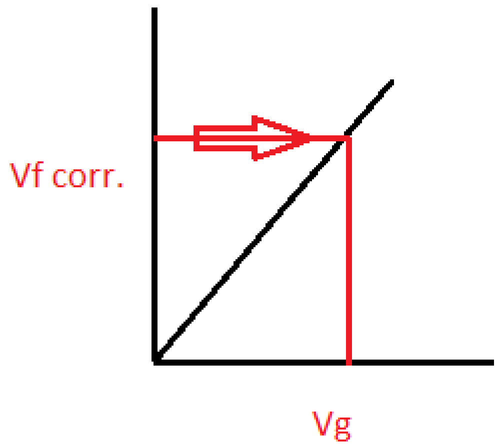
تعتبر من الطرق الحديثة لقياس المسامية , وهي طريقة غير إتلافيه (وذلك لعدم استخدام الزئبق) وذلك بعدم تسليط ضغوط عالية (700 psi) اي الضغط المسلط تقريبا 100 psi))



الغازات المستخدمة

1. الهواء
2. Co2
3. He غاز الهليوم (وهو من الغازات الخاملة؛ لأنّها غازات غير نشيطة كيميائياً, ويُشار إلى أنّ لزوجة الهيليوم تُساوي صفر تقريباً؛ لذلك فإنّه يمرّ من خلال أصغر وأدق الشقوق ويتسرّب بسهولة من فوّهات الأوعية التي يوضع فيها)

$$P_1 \times V_1 = P_2 \times V_2$$



Vf corr.=Vol. of air compressed & Core vol.

$P_1 \times V_{ref} = P_2 \times [V_{ref} + V_{cor} - V_{gra}]$

$P_2 \times V_{gra} = P_2 \times [V_{ref} + V_{cor}] - P1 \times V_{ref}$

$V_{gra} = \frac{P2 \times (Vref + Vcor) - P1 \times Vref}{P2}$

$V_{gra} = (Vref + Vcor) - \frac{p1}{p2} \times Vref = V_{mat}$