Applications of Porosity

- Porosity data are used in these basic reservoir evaluations:

1. Volumetric calculation of fluids in the reservoir
2. Calculation of fluid saturations
3. Geological characterization of the reservoir

- Calculating hydrocarbon in a reservoir

$$HCPV = A \times h \times \phi \times (1 - Swi)$$

where: A = surface area of the reservoir, h = thickness of the formation, ϕ = porosity,

S_{wi}= the percent of the pore volume occupied by the water.

OR

$$N = 7758 \, X \, As \, X \, H \, X \, \phi \, X \, Soi / \, Boi$$

Where: N= HC volume in the reservoir, res.bbl, As = surface area, acres , H= thickness of formation, ft

ϕ = porosity, fraction, Soi = initial oil saturation (1.0 – Swi), fraction, Boi = formation volume factor

Porosity Measurements

- From definition of porosity, porosity of rock sample can be determined by measuring any two of these quantities:
  - ✓ bulk volume
  - ✓ pore volume
  - ✓ grain volume

- Sources of Porosity data:
  - Core analysis – direct measurement
  - Well logging analysis
  - Well testing

  indirect measurement

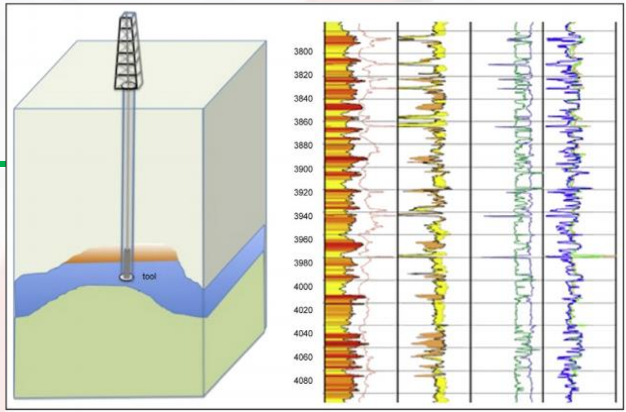
Porosity from logs

3 Main Log Types

- ✓ Bulk density log
- ✓ Sonic (acoustic) log
- ✓ Compensated neutron log

These logs do not measures porosity directly. To accurately calculate porosity, the analyst must know:

- Formation lithology
- Fluid in pores of sampled reservoir volume



➢ Sonic log

$$\Delta t = \Delta t_m (1-\phi) + \Delta t_f (\phi)$$

Where : Dt = sonic travel time recorded by log,

Dt_m = sonic travel time for the matrix mineral grains (w/o porosity), (55.5, 47.5 and 43.5 microsec/ft for quartz, limestone and dolomite, respectively)

Dt_f = sonic travel time for fluid in the pore space (freshwater mud = 189 µsec/ft; saltwater mud = 185 µsec/ft)

ϕ = porosity, fraction

➢ Density log

$$\Delta\rho_{\mathbf{b}} = \Delta\rho_{\mathbf{m}} (\mathbf{1} - \phi) + \Delta\rho_{\mathbf{f}} (\phi)$$

$\Delta\rho_b$ = bulk density recorded by log

$\Delta\rho_m$ = density of the matrix mineral grains (w/o porosity), (2.65, 2.71 and 2.87 gm/cc for quartz, limestone and dolomite, respectively)

$\Delta\rho_f$ = density of the fluid in the pore space (1 – 1.1 gm/cc)

Lab. Measurements of porosity

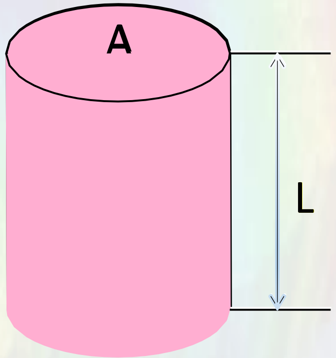
- Several methods: involves only the determination of two out of three basic parameters (V_p, V_m, & V_b)
- **Note:** all methods of determination of bulk volume are in general applicable to determining both total and effective porosity.

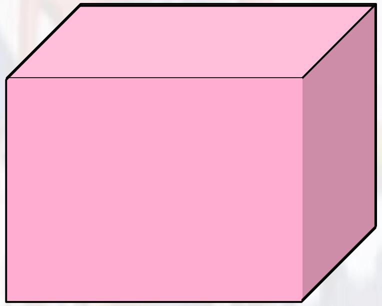
- ***Bulk volume*** by the following methods
  - Coated sample with paraffin or a similar substance and immersed in water, or
  - Water-saturated sample immersed in water, or saturating the sample with the fluid into which it is to immersed.
  - Using mercury (Dry sample immersed in Hg method)
- ***Grain volume***: by Melcher- Nutting method in which the sample is crushed and its volume measured with a pycnometer
- ***Pore volume*** : by Boyle's Law porosimeter (determined using gas expansion methods)

Lab. Measurements of porosity

- ***Porosity measurement***
  - V_b, bulk volume directly measured (Irregular & regular sample shapes)

➢ Direct measure, V_b
Common shaped sample (cylinder, or cubic) measured the dimensions and consider bulk volume





❖ To measure V_b in laboratory, must prevent fluid penetration into the pore sample by:
- coating with wax
- saturating the core with same fluid
- using mercury

❖ Example 1.1 – Porosity Calculation

➢ Determination of V_b – Coating Method (A sand stone sample with ρm = 2.67 gm/cc)

- A = mass dry sample in air = 20.0 gm
- B = mass dry sample coated with paraffin = 20.9 gm $Sg_{paraffin} = 0.9$
- C = mass of coated sample immersed in H_2O at 40°F = 10 gm ($Sg_{water} = 1.0$)
- Mass of paraffin = B – A = 20.9 – 20.0 = 0.9 gm
- Volume of paraffin = 0.9/0.9 = 1 cc
- Mass of water displaced = B – C = 20.9 – 10.0 = 10.9 gm
- Vol. of water displaced = mass of water/ρ of water = 10.9/1.0 = 10.9 cc
- Bulk volume = volume of water displaced – volume paraffin
- = 10.9 – 1.0 = 9.9 cc
- Bulk volume of rock = 9.9 cc

Example 1.2 – Porosity Calculation

- From Example 1.1
- Mass of dry sample in air = 20 gm
- Bulk volume of sample = 9.9 cc
- Grain volume of sample = (mass of dry sample in air)/ (sand-grain density)
- = 20/2.67 = 7.5 cc
- Total porosity = $\varnothing_t$ = [(bulk vol. – grain vol.)/bulk volume] x 100
- = [(9.9 – 7.5)/9.9] x 100 = 24.2 per cent

Grain density of some minerals

Rock	Density (gm/cc)
Sandstone	2.65
Limestone	2.71
Dolomite	2.87
Anhydrite	2.98
Salt	2.17- 2.05
gypsum	2.35
feldspars	2.50-2.67
water	1

Example 1.3

- A clean and dry core sample weighting 425g was 100% saturated with a 1.07 specific gravity brine. The new weight is 453g. The core sample is 12 cm long and 4 cm in diameter. Calculate the porosity of the rock sample.

❖ SOLUTION:

The bulk volume of the core sample is:

$Vb = \pi(r)^2 (12) = 150.80\ cm^3$

The pore volume is:

$Vp = 1/\text{ɥ}\ (V_{wet} - V_{dry}) = (453-425)/1.07 = 26.17\ cm^3$

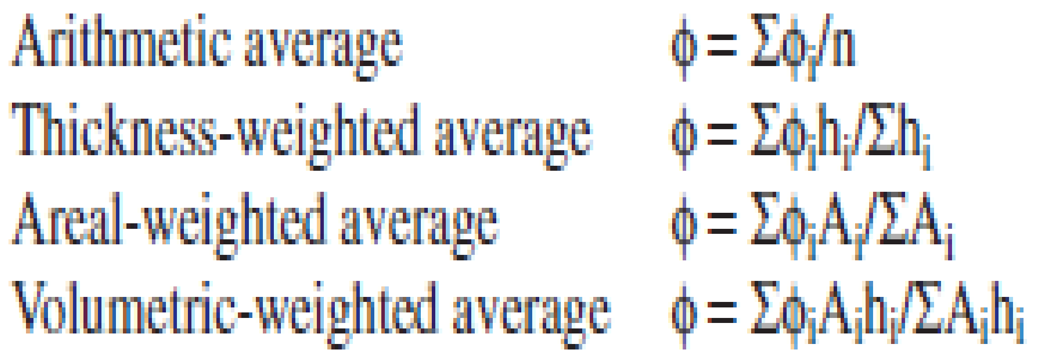
- Then; Porosity of the core is:

$\phi = Vp/Vb = 26.17 / 150.8 = 0.173$ or 17.3%

Variation of porosity with depth

- The reservoir rock may generally show large variations in porosity vertically but does not show very great variations in porosity parallel to the bedding planes. In this case, the arithmetic average porosity or the thickness-weighted average porosity is used to describe the average reservoir porosity.
- A change in sedimentation or depositional conditions, however, can cause the porosity in one portion of the reservoir to be greatly different from that in another area. In such cases, the ***areal weighted average*** or the ***volume-weighted average porosity*** is used to characterize the average rock porosity.

❑ These averaging techniques are expressed mathematically in the following forms:



Arithmetic average	$\phi = \Sigma\phi_i/n$
Thickness-weighted average	$\phi = \Sigma\phi_i h_i/\Sigma h_i$
Areal-weighted average	$\phi = \Sigma\phi_i A_i/\Sigma A_i$
Volumetric-weighted average	$\phi = \Sigma\phi_i A_i h_i/\Sigma A_i h_i$

where n = total number of core samples
h_i = thickness of core sample i or reservoir area i
Ø= porosity of core sample i or reservoir area i
A_i = reservoir area i

❖Example

- Calculate the arithmetic average and thickness-weighted average from the following measurements:

sample	Thickness, ft	Porosity %
1	1	10
2	1.5	12
3	1	11
4	2	13
5	2.1	14
6	1.1	10

- ***<u>Solution:</u>***

- Arithmetic average:

$$\emptyset = \frac{10 + 12 + 11 + 13 + 14 + 10}{6} = 11.67\%$$

- Thickness – weighted average

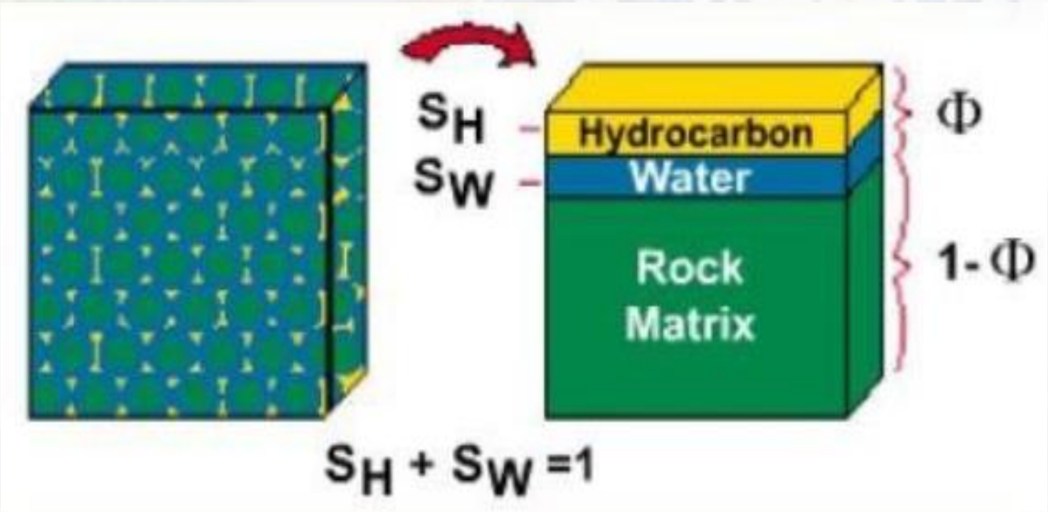
$$\emptyset = \frac{(1)(10)+(1.5)(12)+(1)(11)+(2)(13)+(2.1)(14)+(1.1)(10)}{1+1.5+1+2+2.1+1.1} = 12.11\%$$

Saturation

- ***Saturation*** is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$Fluid\ saturation = \frac{total\ volume\ of\ the\ fluid}{pore\ volume}$$

- Applying the above mathematical concept of saturation to each reservoir fluid gives:
- $oil\ saturation(S_o) = \frac{volume\ of\,oil\ \ (V_o)}{pore\ volume\ \ (V_P)}$
- Water $saturation(S_w) = \frac{volume\ of\ water\ \ (V_w)}{pore\ volume\ \ (V_P)}$
- gas $saturation(S_g) = \frac{volume\ of\ gas\ \ (V_{gs})}{pore\ volume\ (V_P)}$



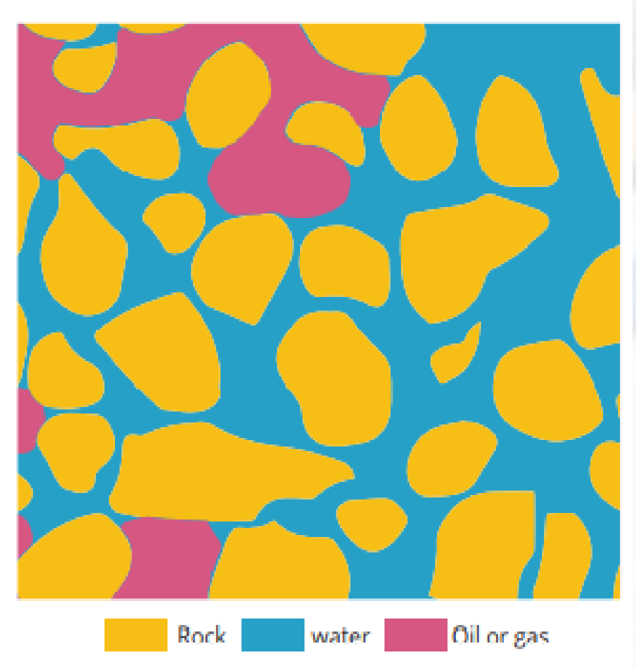
- Thus, all saturation values are based on pore volume.
- The saturation of each individual phase ranges between zero to 100%. By definition, the sum of the saturations is 100%, therefore:

$$Sg + So + Sw = 1.0$$

- The fluids in most reservoirs are believed to have reached a state of equilibrium.
- It is important to note that hydrocarbon saturation rather than water saturation is of prime interest to the explorationist.
- Hydrocarbon saturation is usually determined by the difference between unity and water saturation:

$$S_h = 1 - S_w$$

- The major saturation types of interest in a Reservoir are: ***Critical Oil saturation, Soc*** ; ***Movable oil saturation, Som*** ; ***Residual Oil Saturation, Sor*** ; ***Connate water Saturation, Swc***



- ***Critical oil saturation, Soc***

For the oil phase to flow, the saturation of the oil must exceed a certain value, which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow.

- ***Residual oil saturation, Sor***

During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment), there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the *critical oil saturation.* This saturation value is called the *residual oil saturation, Sor.* The term residual saturation is usually associated with the no wetting phase when it is being displaced by a wetting phase.

- ***Movable oil saturation, Som***

Movable oil saturation Som is another saturation of interest and is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

$$Som = 1 - Swc - Soc$$

Where: Swc = connate water saturation , Soc = critical oil saturation

Critical gas saturation, Sgc

As the reservoir pressure declines below the bubble-point pressure, gas evolves from the oil phase and consequently the saturation of the gas increases as the reservoir pressure declines. The gas phase remains immobile until its saturation exceeds a certain saturation, called *critical gas saturation,* above which gas begins to move.

Critical water saturation, Swc

The critical water saturation, connate water saturation, and irreducible water saturation are extensively used interchangeably to define the maximum water saturation at which the water phase will remain immobile.

❖ *Types of Measurements*

There are two methods to determine or measure fluid saturation

- ***Direct:*** using core samples through:
  - Retort distillation
  - Solvent extraction (Dean-Stark method)
  - Centrifugal

❑For lab. Measurement we used the following eq.:

$$S_o = \frac{Weight\ of\ wet\ core, gm - Weight\ of\ dry\ core, gm - Weight\ of\ water, gm}{Pore\ volume, cc} * \frac{1}{Density\ of\ oil, gm/cc}$$

- ***Indirect***: capillary pressure and well log analysis (resistivity logs), also material balance equation.

❖ *Factors Affecting Saturation*

There are many factors that affect saturation. For example, core samples from reservoir get affected by filtrate from drilling mud. The mud can usually be water or oil based and depending on the wettability of the rock could affect saturation differently. Another factor that affects fluid saturation would be the differences in pressure and temperature that are caused by bringing the core sample from the reservoir to the surface. Those differences in pressure and temperature cause fluids such as gas trapped in oil to be released. This is especially important to know when conducting direct measurements to find the fluid saturation using core samples. The reason fluid saturation is very important is that it helps in estimating the amount of hydrocarbons stored in the reservoir.

Average Saturation

- Proper averaging of saturation data requires that the saturation values be weighted by both the interval *thickness (h)* and interval *porosity Ø.* The average saturation of each reservoir fluid is calculated from the following equations:

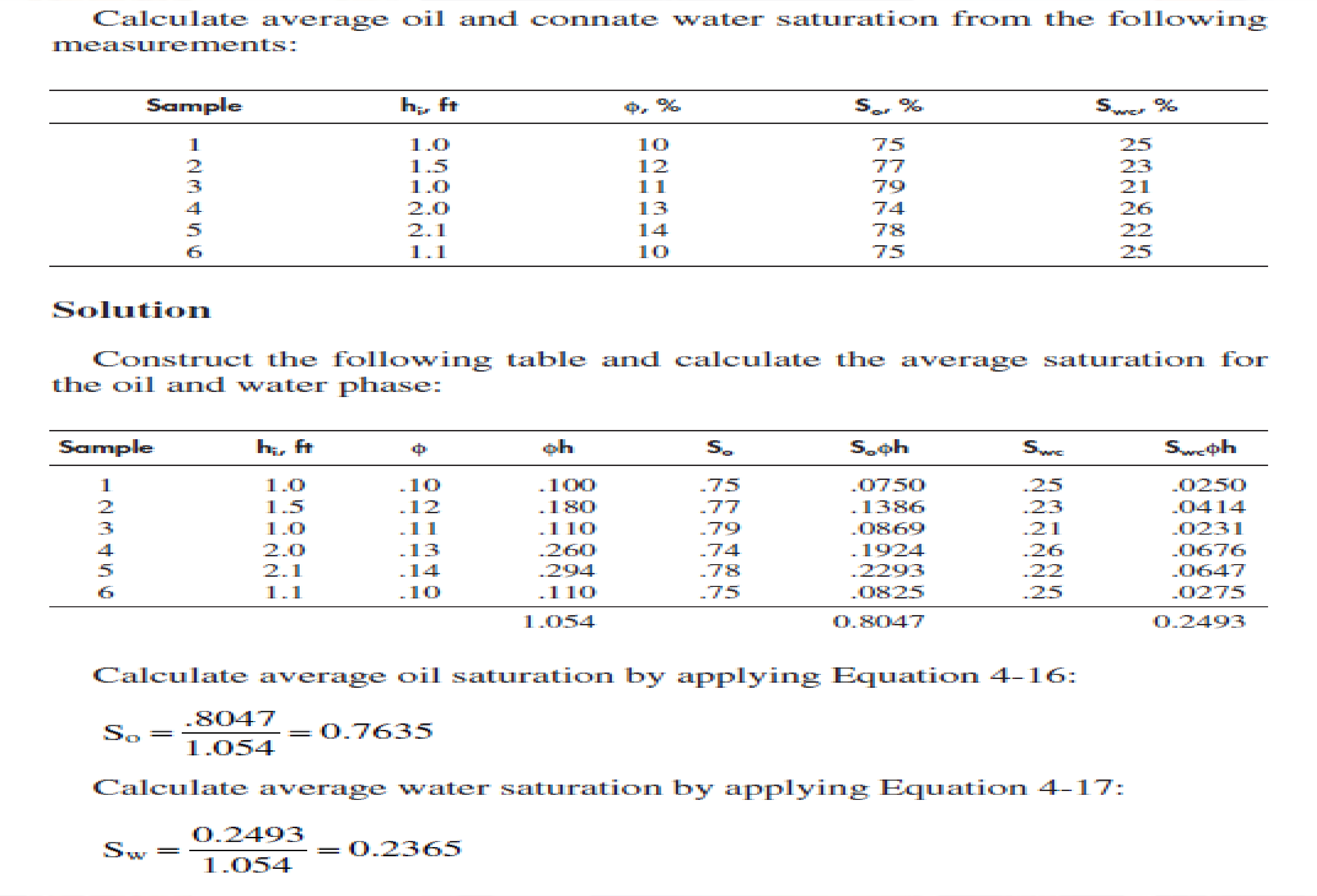
$$S_o = \frac{\sum_{i=1}^{n} \phi_i \, h_i \, S_{oi}}{\sum_{i=1}^{n} \phi_i \, h_i}$$

$$S_w = \frac{\sum_{i=1}^{n} \phi_i \, h_i \, S_{wi}}{\sum_{i=1}^{n} \phi_i \, h_i}$$

$$S_g = \frac{\sum_{i=1}^{n} \phi_i \, h_i \, S_{gi}}{\sum_{i=1}^{n} \phi_i \, h_i}$$

where the subscript i refers to any individual measurement and h_i represents the depth interval to which Ø, S_{oi}, S_{gi}, and S_{wi} apply.

Example



Calculate average oil and connate water saturation from the following measurements:

Sample	h_i, ft	ϕ, %	S_o, %	S_{wc}, %
1	1.0	10	75	25
2	1.5	12	77	23
3	1.0	11	79	21
4	2.0	13	74	26
5	2.1	14	78	22
6	1.1	10	75	25

Solution

Construct the following table and calculate the average saturation for the oil and water phase:

Sample	h_i, ft	ϕ	ϕh	S_o	$S_o \phi h$	S_{wc}	$S_{wc} \phi h$
1	1.0	.10	.100	.75	.0750	.25	.0250
2	1.5	.12	.180	.77	.1386	.23	.0414
3	1.0	.11	.110	.79	.0869	.21	.0231
4	2.0	.13	.260	.74	.1924	.26	.0676
5	2.1	.14	.294	.78	.2293	.22	.0647
6	1.1	.10	.110	.75	.0825	.25	.0275
			1.054		0.8047		0.2493

Calculate average oil saturation by applying Equation 4-16:

$$S_o = \frac{.8047}{1.054} = 0.7635$$

Calculate average water saturation by applying Equation 4-17:

$$S_w = \frac{0.2493}{1.054} = 0.2365$$