Status of liquids and gases in reservoir conditions

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Outline:

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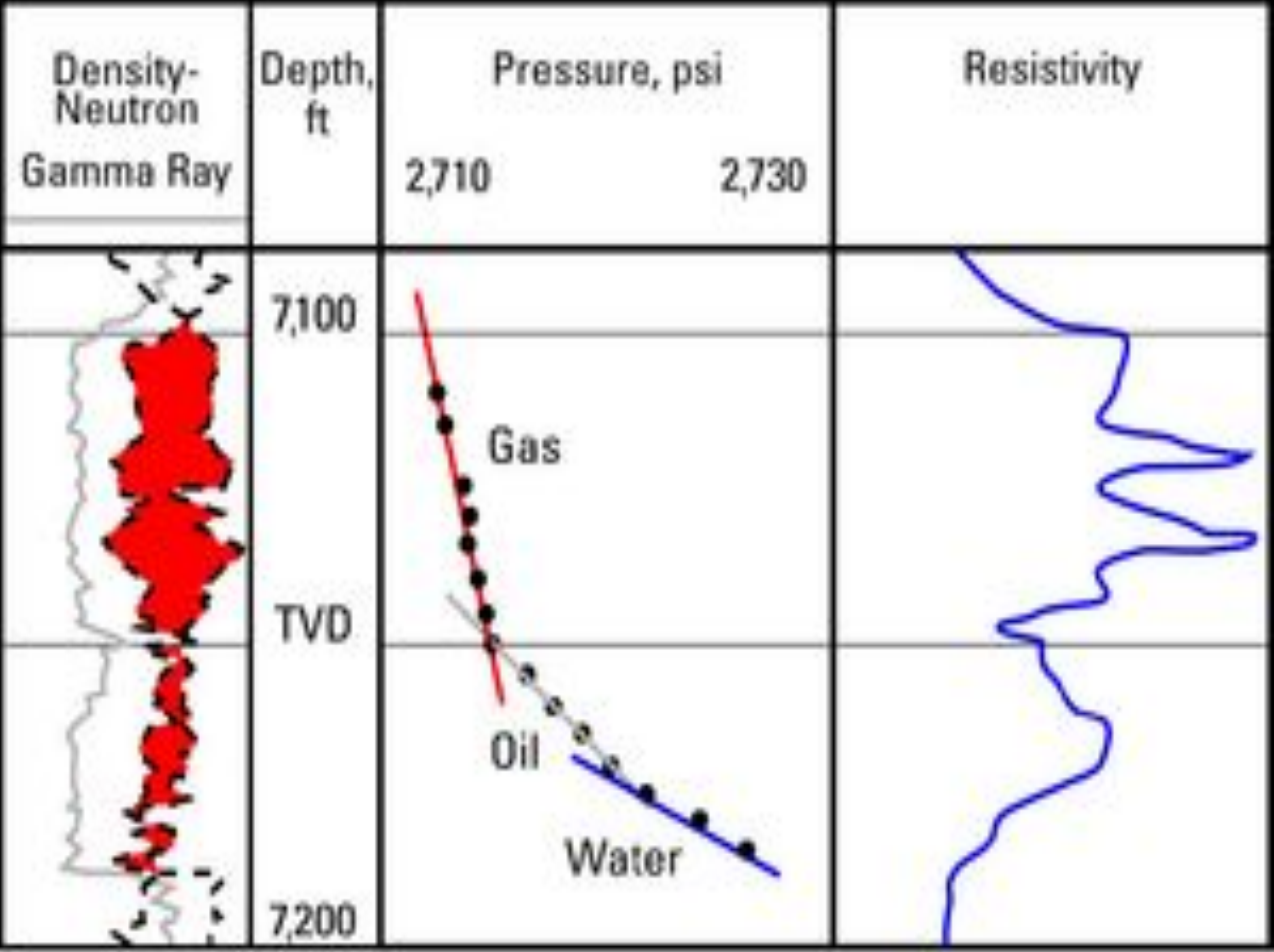
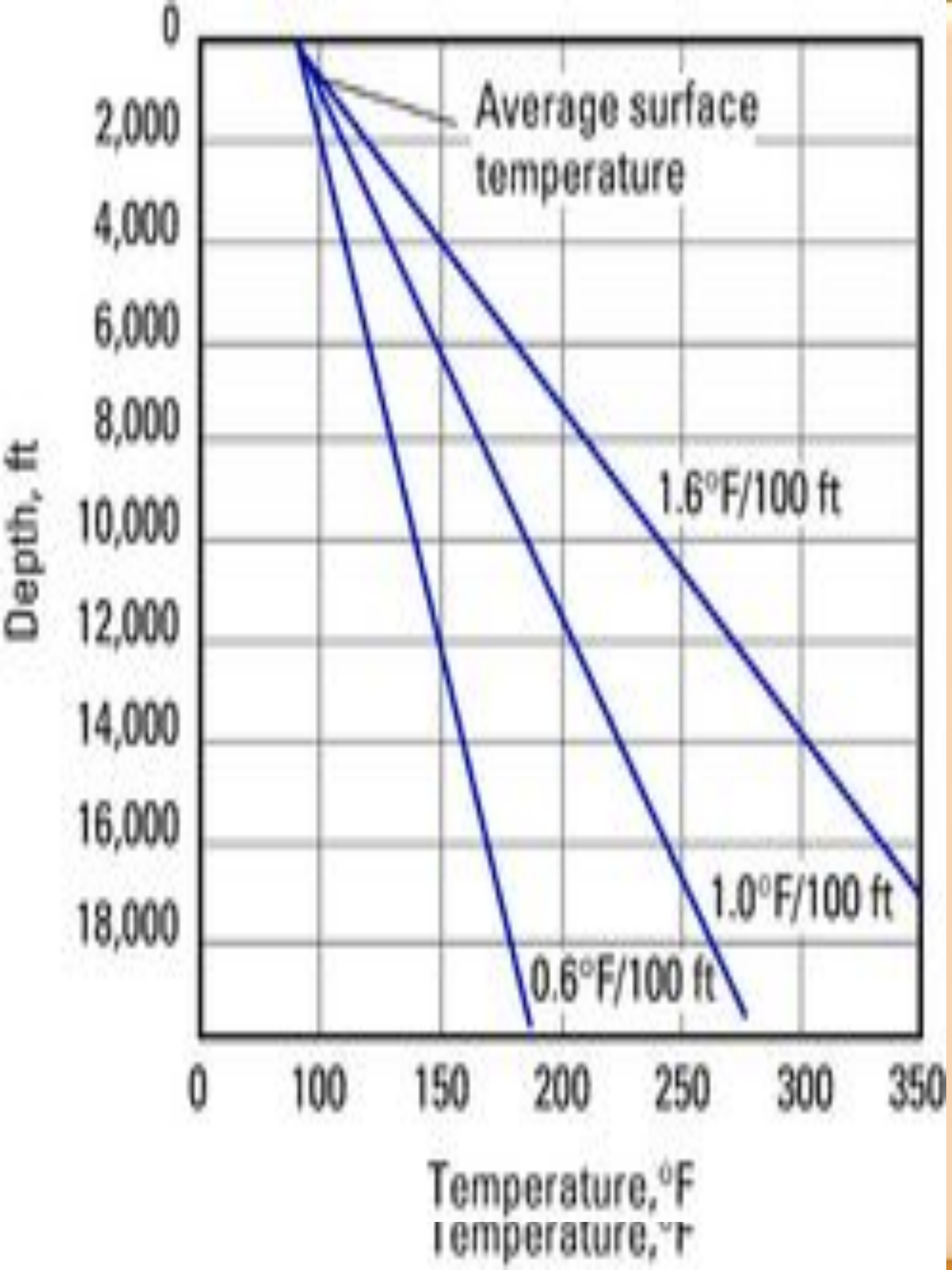
Reservoir pressure and temperature

- practice of using bottomhole pressure measurements to improve oil and gas production and solve problems of reservoir engineering began around 1930. Initially, pressures were calculated using fluid levels; a later method was to inject gas into the tubing until the pressure became constant. The earliest bottomhole pressure measurements were made with one-time-reading pressure bombs and maximum-indicating or maximum-recording pressure gauges that lacked the accuracy, reliability, or durability of present-day technology.
- The varied uses of bottomhole pressure and temperature measurements have increased in scope during the past two decades as instrumentation technologies have produced more reliable and accurate tools. These advances have made more applications possible, including multilayer reservoirs, horizontal wells, interference testing, and drawdown test interpretation


Density-Neutron
Gamma Ray
Depth, ft
Pressure, psi
2,710
2,730
Resistivity
7,100
Gas
TVD
Oil
Water
7,200



Reservoir temperature is governed primarily by the reservoir's proximity to the earth's mantle, and by the relative heat exchange capacities and thermal conductivities of the formations forming the lithostatic sequence that includes the reservoir.

The geothermal gradient resulting from the heat-exchange process varies from basin to basin, but within a specific area the variations are small. In most hydrocarbon-producing areas, the gradient is usually in the range of 0.6 to 1.6°F per 100 ft of depth increase (Fig. 3). Areas where the earth's crust is thinner than average, such as volcanic and geothermal areas, have much higher gradients. In thin-crust areas the gradient change averages 4°F per 100 ft of depth increase. Local temperature gradients at depth have been reported as high as 10°F per 100 ft approaching singularities (e.g., major faults, areas of tectonic movement) in the earth's crust in geothermal areas

Reduced pressure and temperature

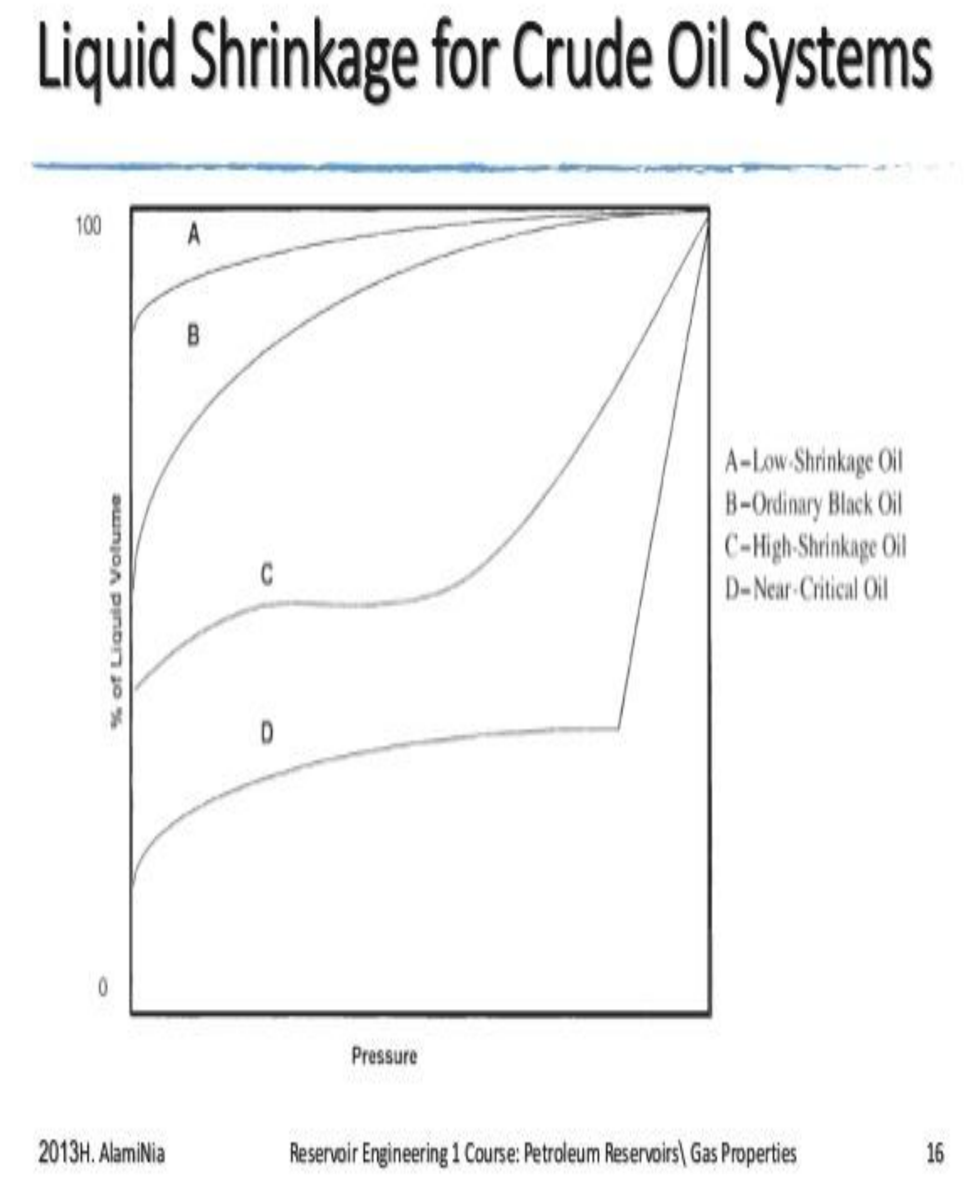
- ***Reduced pressure-the reduced pressure is defined as its actual pressure. P=P:Pc***

- ***The reduced temperature of a fluid is its actual temperature, divided by its critical temperature Tr=Tc:T***

Physical and chemical properties of the oil under reservoir conditions

- **Petroleum is one of the most complex naturally occurring organic mixtures. The physical and chemical properties of petroleum in a reservoir depend on its molecular composition and the reservoir conditions (temperature, pressure). The composition of petroleum varies greatly, ranging from the simplest gas (methane), condensates, conventional crude oil to heavy oil and oil sands bitumen with complex molecules having molecular weights in excess of 1000 daltons (Da). The distribution of petroleum constituents in a reservoir largely depends on source facies (original organic material buried), age (evolution of organisms), depositional environment (dysoxic versus anoxic), maturity of the source rock (kerogen) at time of expulsion, primary/secondary migration, and in-reservoir alteration such as biodegradation, gas washing, water washing, segregation, and/or mixing from different oil charges. These geochemical aspects define the physical characteristics of a petroleum in the reservoir, including its density and viscosity. When the petroleum is released from the reservoir through an oil exploration accident like in the case of the Deepwater Horizon event, several processes are affecting the physical and chemical properties of the petroleum from the well head into the deep sea**

Crude oils in a natural reservoir under pressure contain dissolved natural gases which vaporize as the pressure is released on the oil. Vaporization causes a shrinkage in the volume of the remaining oil. This paper presents methods of predicting the shrinkage from measurements made on a well of gas gravity, oil gravity, gas-oil ratio, reservoir temperature, and reservoir pressure. These data, along with the correlations developed from shrinkage measurements on 117 crude oils, permit calculations of shrinkage with an accuracy approaching that of experimental determinations. Approximate methods of predicting shrinkage are presented when limited field data are available. Shrinkage predictions will assist in converting reservoir petroleum reserves into stock-tank quantities



Liquid Shrinkage for Crude Oil Systems

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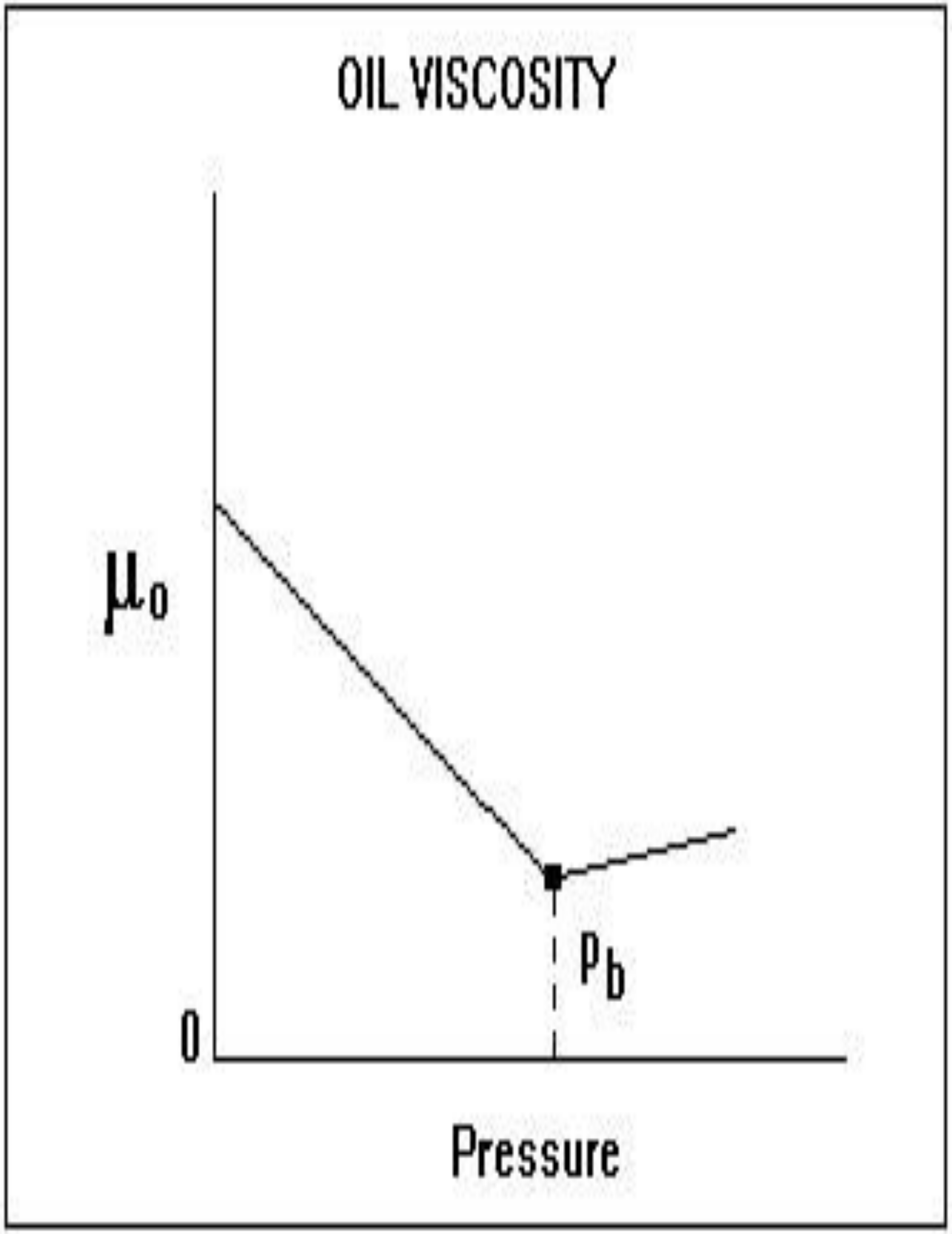
The oil viscosity is measured as a function of pressure in most PVT laboratory measurements. The value corresponding to the average reservoir pressure at the time of the test is the most appropriate value to use. Occasionally, a routine oil analysis report will quote the oil viscosity (and the kinematic viscosity). These measurements are at stock tank conditions and should not be used as the in-situ oil viscosity at reservoir conditions, because of the significant effect of dissolved gas on viscosity.

The Beggs and Robinson correlation is used to calculate the default oil viscosity. Note that this and other oil viscosity correlations are very sensitive to solution gas oil ratio (R_s) and oil gravity (g_o). The oil viscosity at reservoir conditions can vary from 10000 cp for a heavy oil to less than 1 cp for a light oil

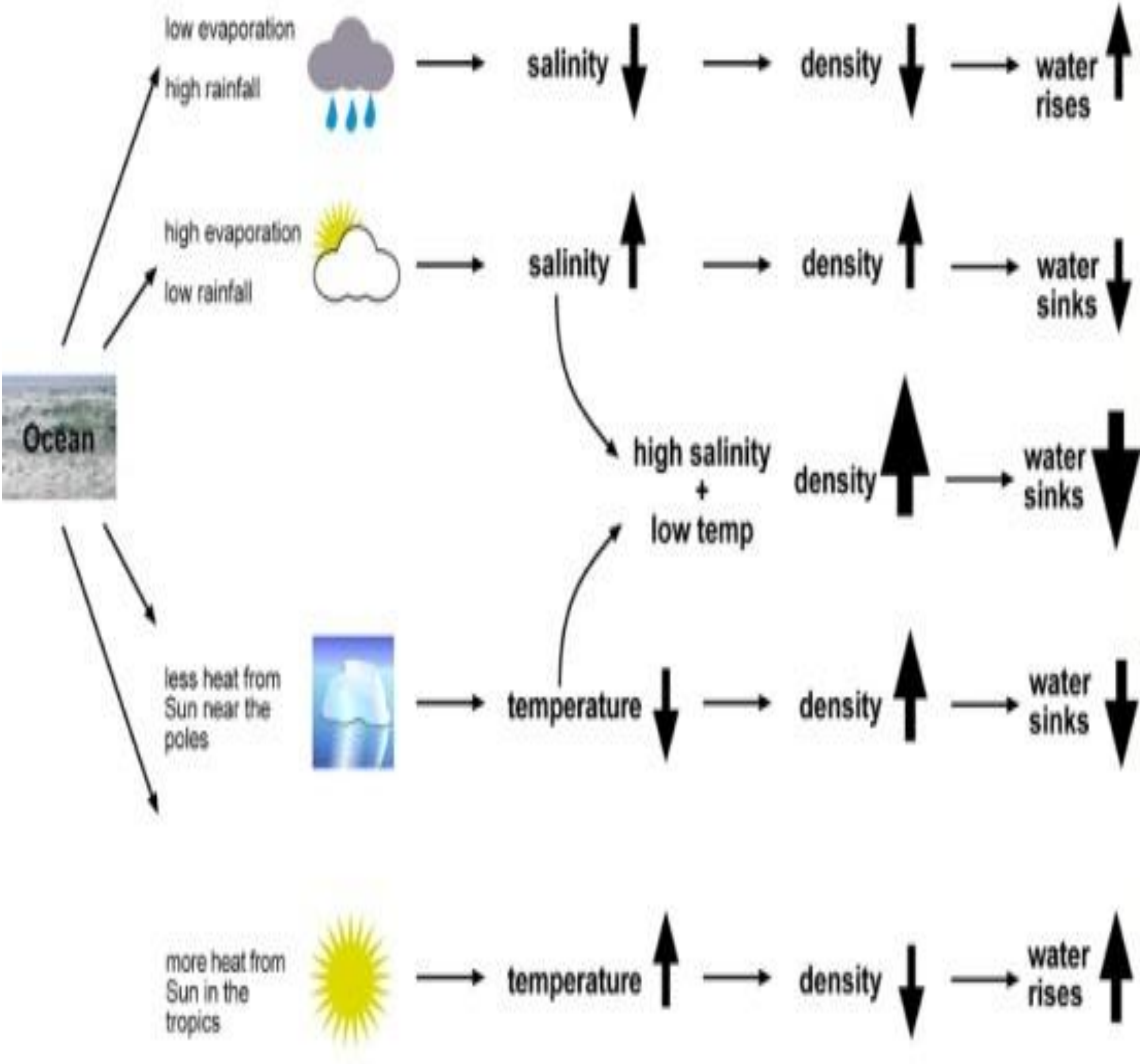


Formation water and their physical properties

- **Formation water exists naturally in the rock all along, before drilling. It is water associated with the oil and gas reservoir and has some outstanding chemical characteristics. Connate water is fossil water that was out of contact with the atmosphere during most part of the geologic age at least. The physical properties of formation water include mainly density, viscosity, and compressibility. These properties may be determined using charts due to fewer changes of these properties of formation water with pressure and temperature than that of crude oil. Thus, the chemical properties of formation water become more important. The salts contained are mainly composed of K+, Na+, Ca2+, Mg2+, Cl−, , , and . The unit mg/liter is generally used as the unit of total salinity (or TDS).**

The density and salinity

Salinity and density share a positive relationship. As density increases, the amount of salts in the water—also known as salinity, increases. Various events can contribute to change in the density of seawater. Salinity can decrease from the melting of polar ice or increase from the freezing of polar ice.



The compressibility of water.

- *Water is essentially incompressible, especially under normal conditions. If you fill a sandwich bag with water and put a straw into it, when you squeeze the baggie the water won't compress, but rather will shoot out the straw. If the water compressed, it wouldn't "push back" out of the straw. Incompressibility is a common property of liquids, but water is especially incompressible.Water's lack of compressibility helps to push water out of water hoses (handy for putting out fires), water pistols (handy for bothering Dad), and in artistic water fountains (handy for relaxing). In these instances, some pressure is applied to a container full of water and rather than compress, it comes shooting out of an opening, such as the end of the hose or the end of a small pipe, as in this fountain. If water was highly compressible, it would be harder to create enough pressure for water to shoot out of the nearest openingKids make good use of water's uncompressibility when they play a game of water-balloon tossing. When you squeeze the balloon too much, the balloon's skin will fail before the water inside compresses—it will burst in your face long before the water will compress even an infinitesimal amount.*

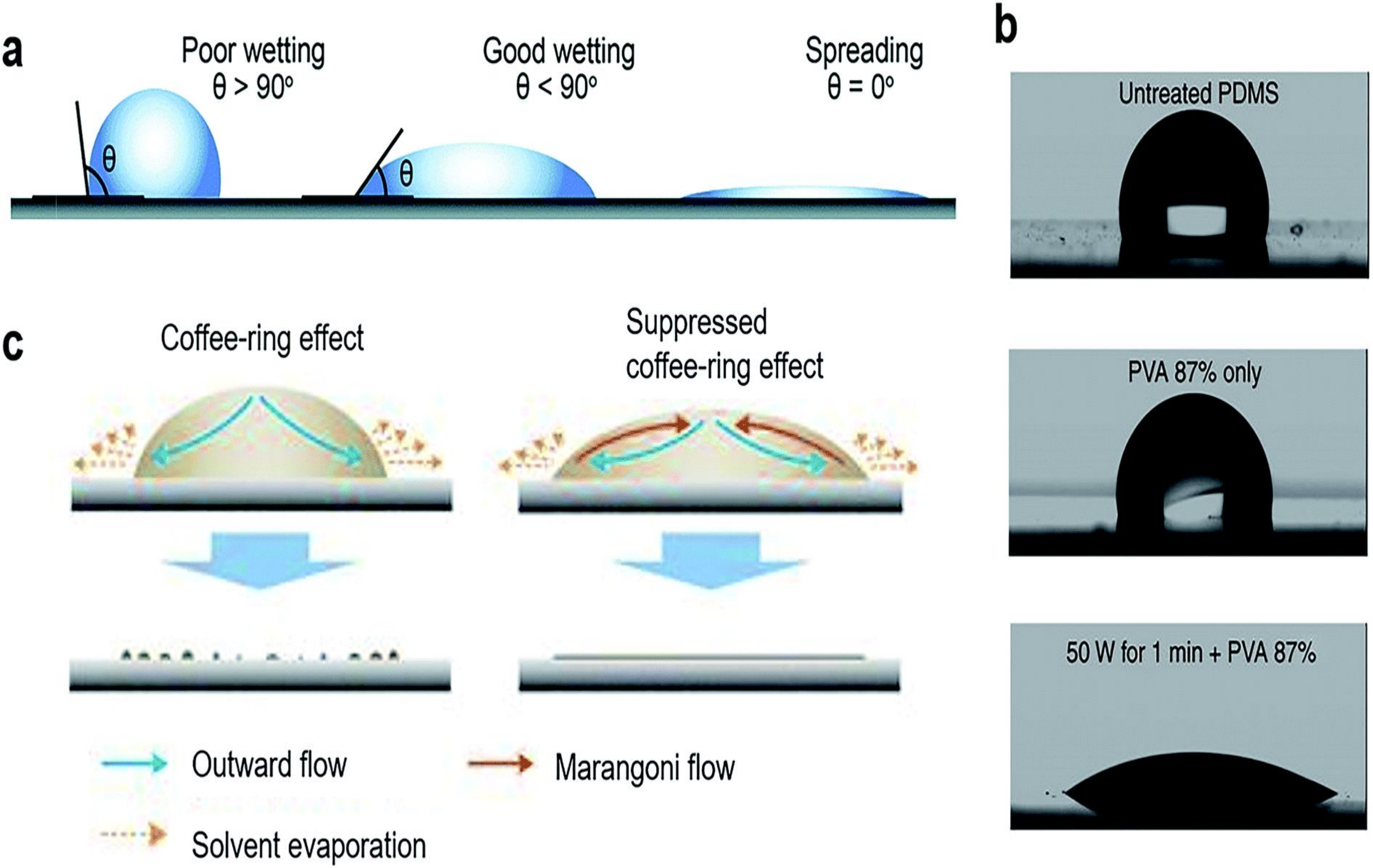
Oil and water saturation of reservoirs

Hydrocarbon saturation is 1 (one) minus the water saturation. Most oil and gas reservoirs are water wet; water coats the surface of each rock grain. A few reservoirs are oil wet, with oil on the rock surface and water contained in the pores, surrounded by oil. Some reservoirs are partially oil wet.

Wetting and the capillary pressure.

Wetting is the ability of a liquid to maintain contact with a solid surface, resulting from intermolecular interactions when the two are brought together. The degree of wetting (wettability) is determined by a force balance between adhesive and cohesive forces. Wetting deals with the three phases of materials: gas, liquid, and solid. It is now a center of attention in nanotechnology and nanoscience studies due to the advent of many nanomaterials in the past two decades (e.g. graphene,[1] carbon nanotube, boron nitride nanomesh[2]).Wetting is important in the bonding or adherence of two materials.[3] Wetting and the surface forces that control wetting are also responsible for other related effects, including capillary effects.There are two types of wetting: non-reactive wetting and active wetting

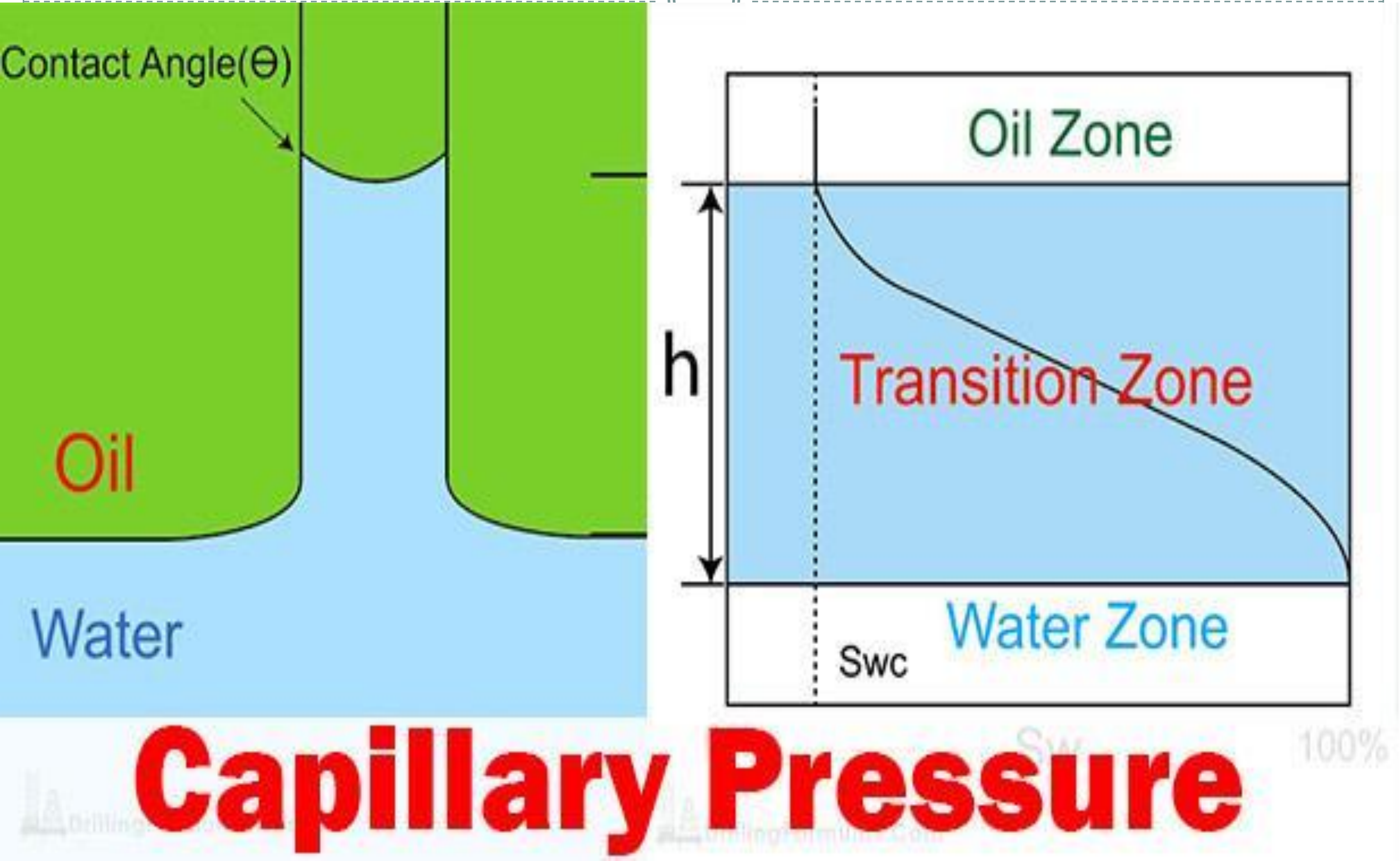
Wetting


a
Poor wetting
θ > 90º
θ
Good wetting
θ < 90º
θ
Spreading
θ = 0º
b
Untreated PDMS
PVA 87% only
50 W for 1 min + PVA 87%
c
Coffee-ring effect
Suppressed
coffee-ring effect
Outward flow
Marangoni flow
Solvent evaporation

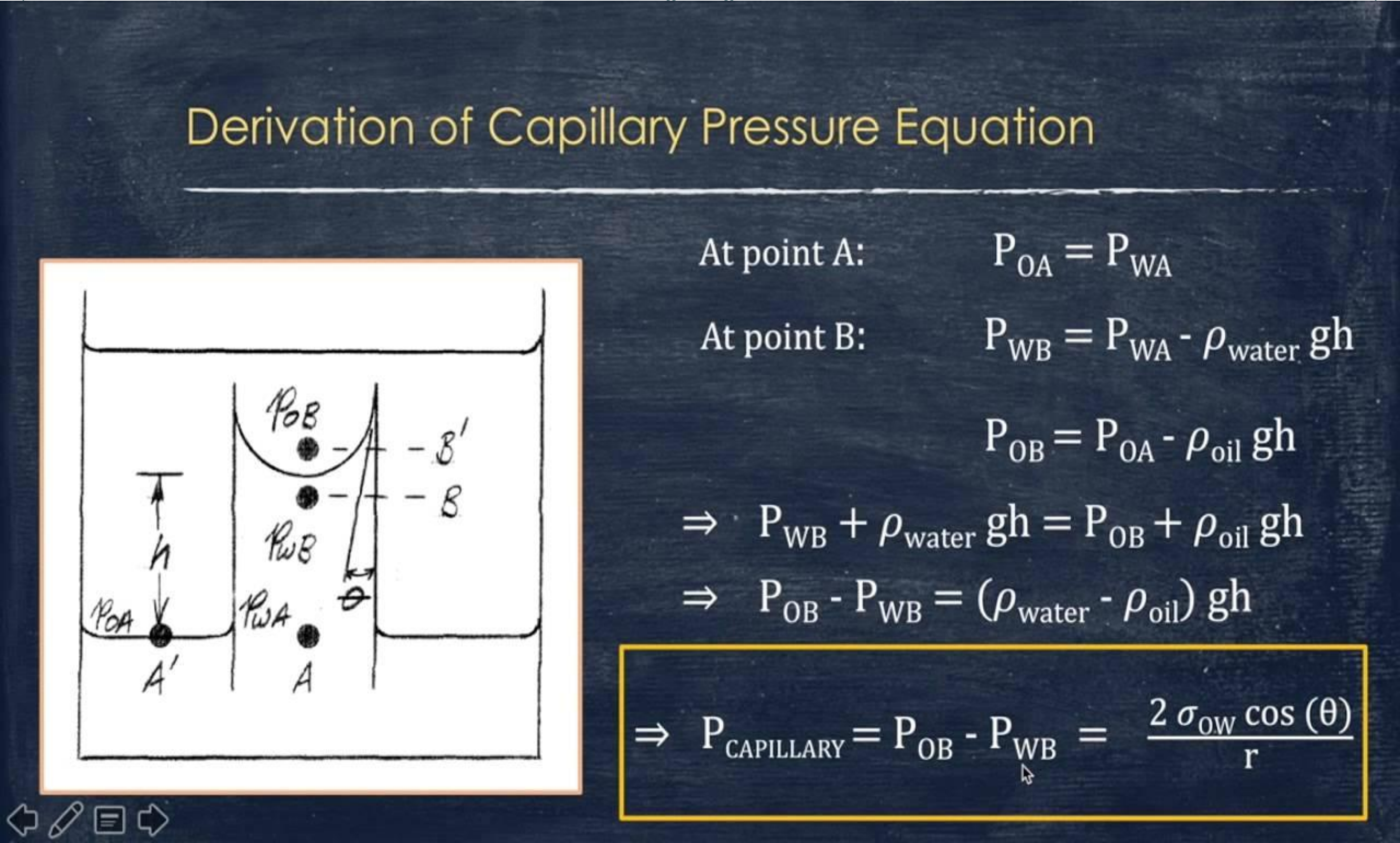
Wetting and the capillary pressure.

- ***The wetting phase is identified by its ability to preferentially diffuse across the capillary walls before the non-wetting phase. The "wettability" of a fluid depends on its surface tension, the forces that drive a fluid's tendency to take up the minimal amount of space possible, and it is determined by the contact angle of the fluid.[1] A fluid's "wettability" can be controlled by varying capillary surface properties (e.g. roughness, hydrophilicity). However, in oil-water systems, water is typically the wetting phase, while for gas-oil systems, oil is typically the wetting phase. Regardless of the system, a pressure difference arises at the resulting curved interface between the two fluids.[2]***

Capillary Pressure



Capillary pressure



Derivation of Capillary Pressure Equation

At point A: $P_{OA} = P_{WA}$

At point B: $P_{WB} = P_{WA} - \rho_{water}\, gh$

$$P_{OB} = P_{OA} - \rho_{oil}\, gh$$

$$\Rightarrow \quad P_{WB} + \rho_{water}\, gh = P_{OB} + \rho_{oil}\, gh$$

$$\Rightarrow \quad P_{OB} - P_{WB} = (\rho_{water} - \rho_{oil})\, gh$$

$$\boxed{\Rightarrow \quad P_{CAPILLARY} = P_{OB} - P_{WB} = \frac{2\,\sigma_{OW} \cos(\theta)}{r}}$$

Thank You

For Your Attention