Sudan University of Science and Technology
College of Petroleum Engineering and Technology

Reservoir Engineering 3
(Flow through Porous Media and Applied Reservoir Engineering)

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Last Update Sep. 2012

Mode of Delivery and Assessment:

Delivery: 2 hours Lecture + 2 hours tutorial per week

Assessment: 33.5% continuous assessment + 66.5% University examination

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Continuous Assessment: consists of (7-8 Hws + 5 Quizes + 2 tests)

Objectives

- To present the fundamentals of reservoir engineering methods used in description and evaluation of oil and gas reservoirs.

Contents

- Introduction: Review of reservoir properties
- Basic Equations of Fluid Flow Through Porous Media: Fundamentals of Reservoir Fluid Flow, Darcy law, single phase and multi- phase flow, linear, radial and spherical flow, compressible and ideal gas flow, steady state and unsteady state flow, applications.

Contents continue….

- **Oil Reservoirs:** Classification of hydrocarbon reservoirs according to P-T diagram, review of PVT of oil reservoirs, oil formation volume factor and solution gas oil ratio, MBE for volumetric under saturated reservoirs, MBE for reservoirs above the bubble point pressure, effect of rock and water compressibility.

Test No. 1

Contents continue….

- **Water Influx Calculations:** Schilthuis steady state, Hurst modified steady state, Van Everding and Hurst unsteady state, dimensionless time and dimensionless water influx, variable pressure and the principle of superposition.
- **Prediction of reservoir performance:** Material balance equation, producing GOR equation relative permeability ratio, Tarner’s method, Tracy’s modification Muskat method, Pirson’s method.

References

- Craft, Hawkins, and Terry, 1991. “Applied Petroleum Reservoir Engineering”, second edition.
- Brian F Towler. “Fundamental Principles of Reservoir Engineering”, Textbook vol. 8.
- Tareq Ahmed. “ Reservoir Engineering Handbook” Text Book 2001, Elsevier group.
- SPE, 2007. “Reservoir Engineering”

Introduction

- **Reservoir Rock Properties:**

Porosity: defined as the ratio of void space, or pore volume, to the total bulk volume of the rock. This ratio expressed either as a fraction or in percent.

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}}$$

where ϕ = porosity

It usually obtaine ogs (neutron, sonic or density) (average), core analysis (specific but small piece of the rock).

Porosity often decreases as the depth of the formation increase

1. Absolute Porosity

2. Effective Porosity

The effective porosity is the percentage of *interconnected* pore space with respect to the bulk volume, or

$$\phi = \frac{\text{interconnected pore volume}}{\text{bulk volume}} \qquad (4\text{-}3)$$

where ϕ = effective porosity.

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Permeability

- Permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability, K is very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation.

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

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

$$S_o = \frac{\text{volume of oil}}{\text{pore volume}} \qquad S_g = \frac{\text{volume of gas}}{\text{pore volume}} \qquad S_w = \frac{\text{volume of water}}{\text{pore volume}}$$

- All saturation values are based on pore volume and not on the gross reservoir volume.

$$S_g + S_o + S_w = 1.0$$

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- In addition to the bottom (or edge) water, there will be *connate water* distributed through out the oil and gas zones. Connate (interstitial) water saturation S_{wc} is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table. Another particular phase saturation of interest is called *critical saturation*.

- **Critical Oil Saturation, S_{oc}**

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 purpose, will not flow.

- **Residual Oil Saturation, S_{or}**

During the displacing process of the crude oil system from the porous media by water or gas injection 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*. The term residual saturation is usually associated with the nonwetting phase when it is being displaced by a wetting phase

- **Movable Oil Saturation, S_{om}**

Is another saturation of interest defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

$$S_{om} = 1 - S_{wc} - S_{oc}$$

where S_{wc} = connate water saturation
S_{oc} = critical oil saturation

- **Critical Gas Saturation, S_{gc}**

As the reservoir P declines below the bubble point P, 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, S_{wc}**

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

- **Average Saturation**

Proper averaging of saturation data required that the saturation values be weighted by both the interval thickness h_i and interval porosity. The average saturation of each reservoir fluid is calculated from the following equations:

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

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

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

where the subscript i refers to any individual measurement and h_i presents the depth interval to which ϕ_i , S_{oi}, S_{gi}, and S_{wi} y.

- **Wettability:**

the capacity of a liquid to spread on a given surface is called wettability. It is a function of the type of fluid and the solid surface.

Methods of calculating wettability include measurements of threshold pressures, determining areas under Pc curves, and by direct measurement of contact angles using core surfaces and reservoir fluids.

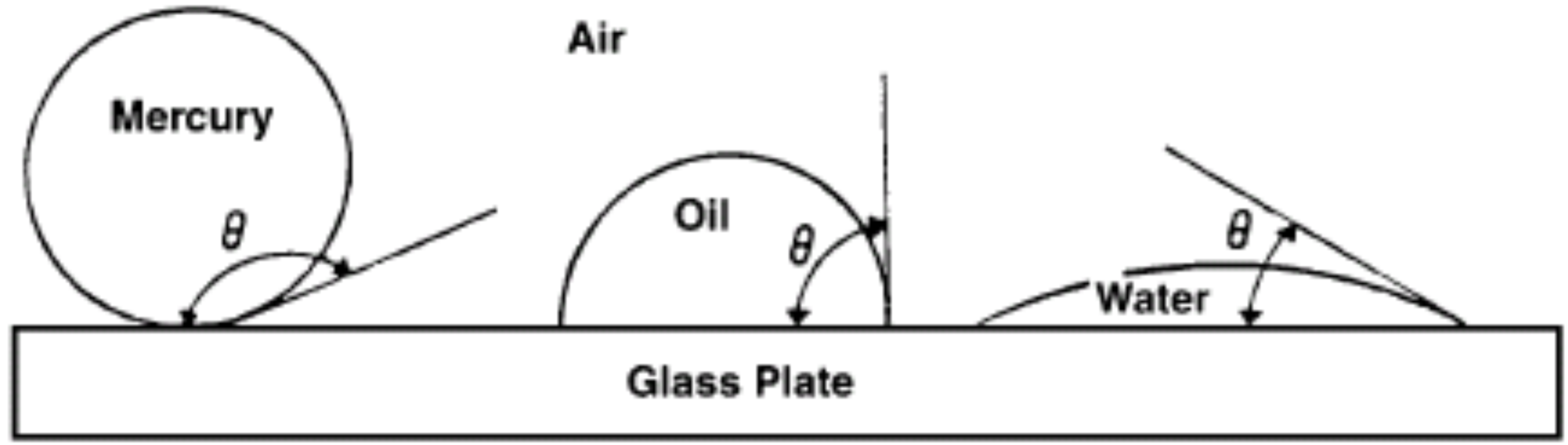

Figure 4-1. Illustration of wettability.

- The angle of contact at the *liquid - solid surface* is called *contact angle*.

The wettability of reservoir rocks to the fluids is important in that the distribution of the fluids in the porous media is a function of wettability. Because of the attractive forces, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more open channels.

- **Surface and Interfacial Tension**

in dealing with multiphase systems, it is necessary to consider effect of the forces at the interface when two immiscible fluids are in contact. When these 2 fluids are liquid and gas , the term *surface tension* is used to describe the forces acting on the interface. When the interface is between 2 liquids, the acting forces are called *interfacial tension*. The surface or interfacial tension has the units of force per unity of length, e.g. dynes/cm and usually denoted by the symbol σ.

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- **Capillary Pressure:**

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system

- When 2 immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids. This pressure difference is called *capillary pressure p_c*

The displacement of one fluid by another in the pores of a porous medium is either aided or opposed by the surface forces of capillary pressure.

Capillary pressure = (pressure of the nonwetting phase) – (pressure of the wetting phase)

$$p_c = p_{nw} - p_w$$

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- There are three types of capillary pressure:

  - Water-oil capillary pressure (denoted as P_{cwo})
  - Gas-oil capillary pressure (denoted as P_{cgo})
  - Gas-water capillary pressure (denoted as P_{cgw})

$$p_{cwo} = p_o - p_w$$

$$p_{cgo} = p_g - p_o$$

$$p_{cgw} = p_g - p_w$$

- If all the three phase are continuous, then:

$$p_{cgw} = p_{cgo} + p_{cwo}$$

$$p_c = gh\,(\rho_w - \rho_{air}) = gh\Delta\rho$$

$$p_c = \left(\frac{h}{144}\right)\Delta\rho$$

where p_c = capillary pressure, psi
h = capillary rise, ft
$\Delta\rho$ = density difference, lb/ft^3

- In the case of an oil – water system:

$$p_c = gh\,(\rho_w - \rho_o) = gh\Delta\rho$$

and in practical units

$$p_c = \left(\frac{h}{144}\right)(\rho_w - \rho_o)$$

- Gas Liquid System

$$P_c = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r}$$

$$h = \frac{2\,\sigma_{gw}\,(\cos\theta)}{r\,g\,(\rho_w - \rho_{gas})}$$

where ρ_w = water density, gm/cm^3
σ_{gw} = gas-water surface tension, dynes/cm
r = capillary radius, cm
θ = contact angle
h = capillary rise, cm
g = acceleration due to gravity, cm/sec^2
p_c = capillary pressure, dynes/cm^2

- Oil – Water System

$$p_c = \frac{2\,\sigma_{ow}\,(\cos\theta)}{r}$$

and

$$h = \frac{2\,\sigma_{wo}\,(\cos\,\theta)}{r\,g\,(\rho_w - \rho_o)}$$

where σ_{wo} is the water-oil interfacial tension.

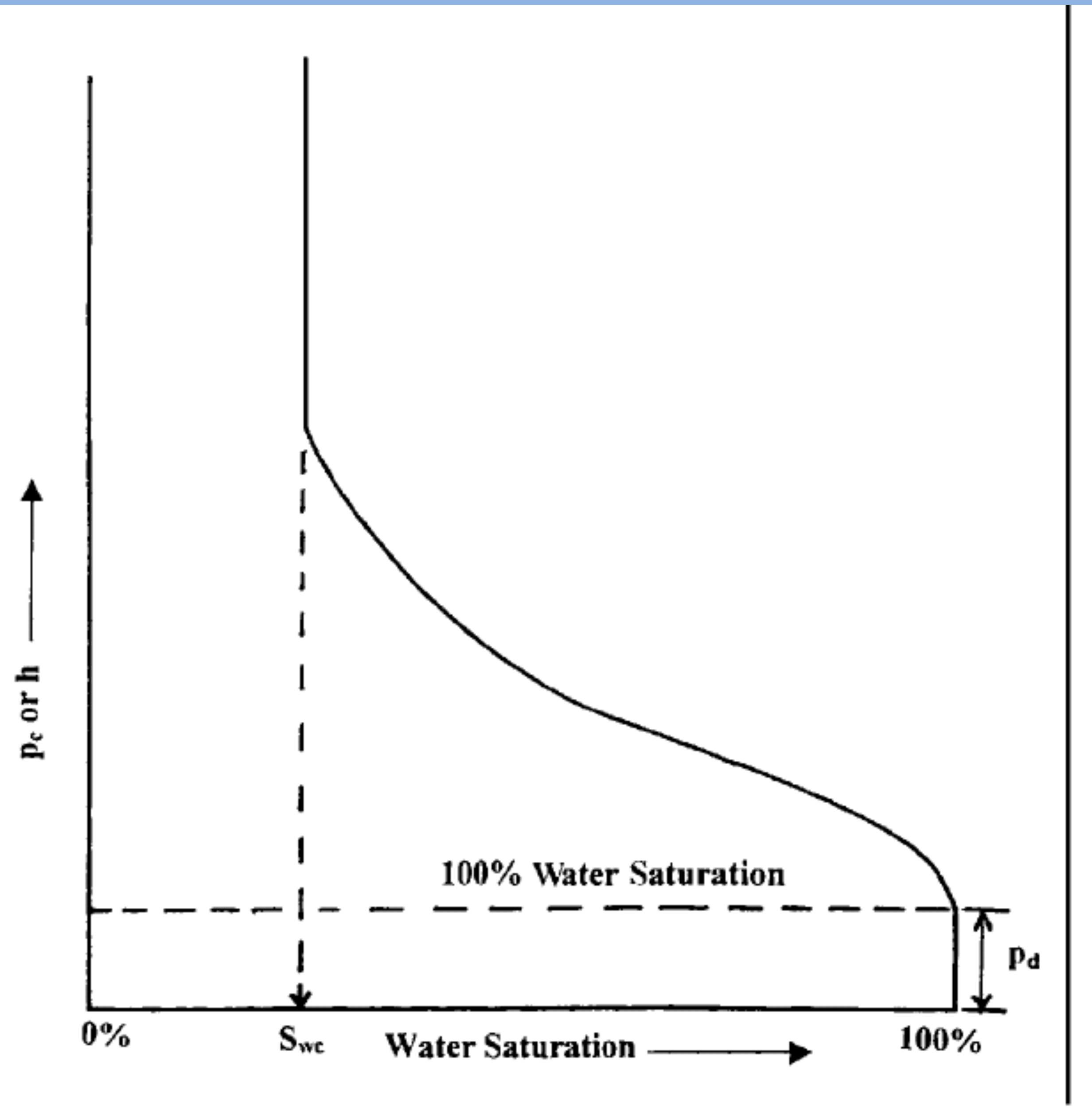

Figure 4-5. Capillary pressure curve.

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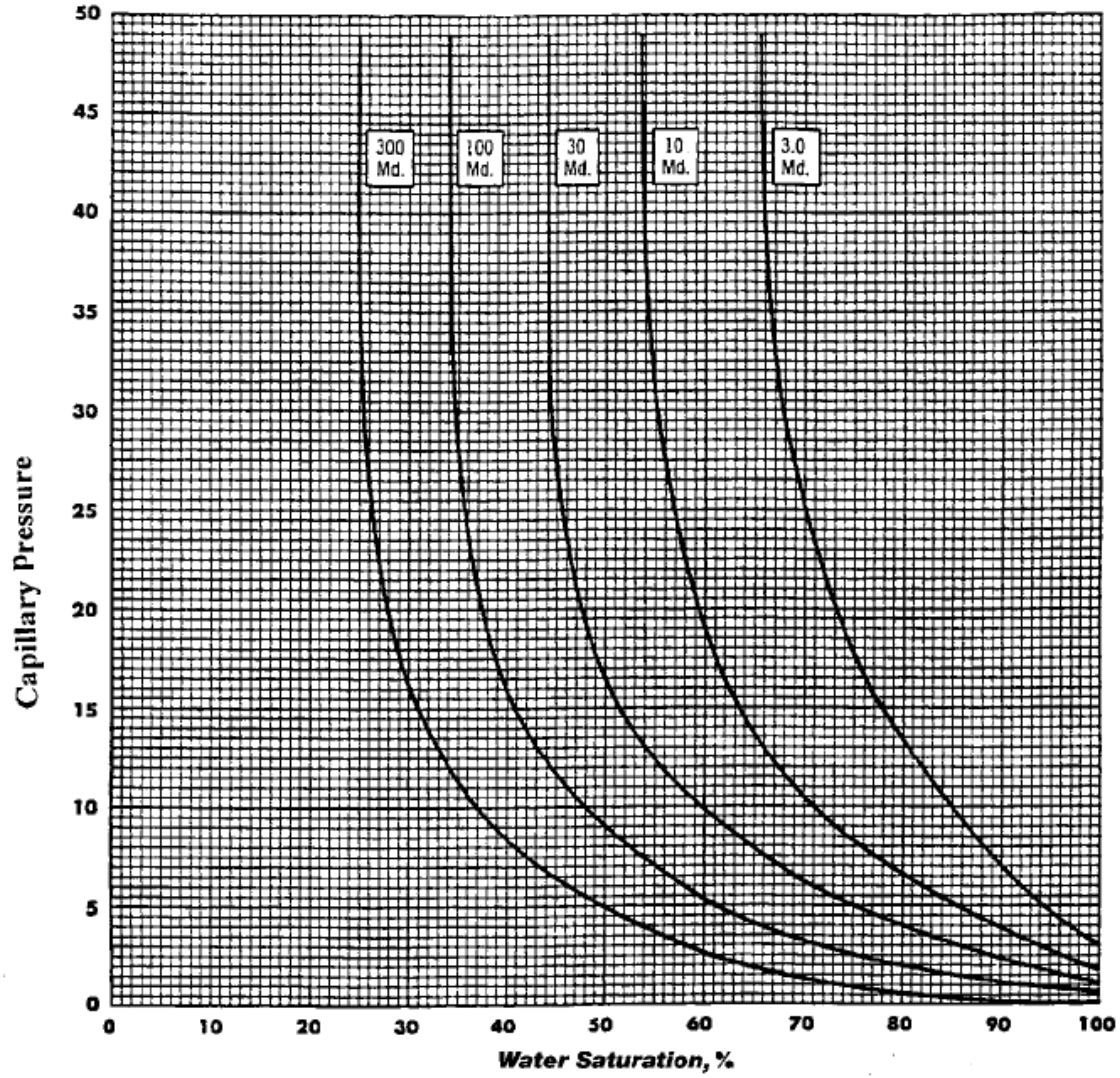

Figure 4-6. Variation of capillary pressure with permeability.

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Drainage and Imbibition capillary pressure

The process of generating the Pc curve by displacing the wetting phase (water) with the nonwetting phase (gas or oil) is called *drainage process*. Process of displacing nonwetting phase with wetting phase is termed the *imbibition* and the resulting curve is termed the capillary pressure imbibition curve.

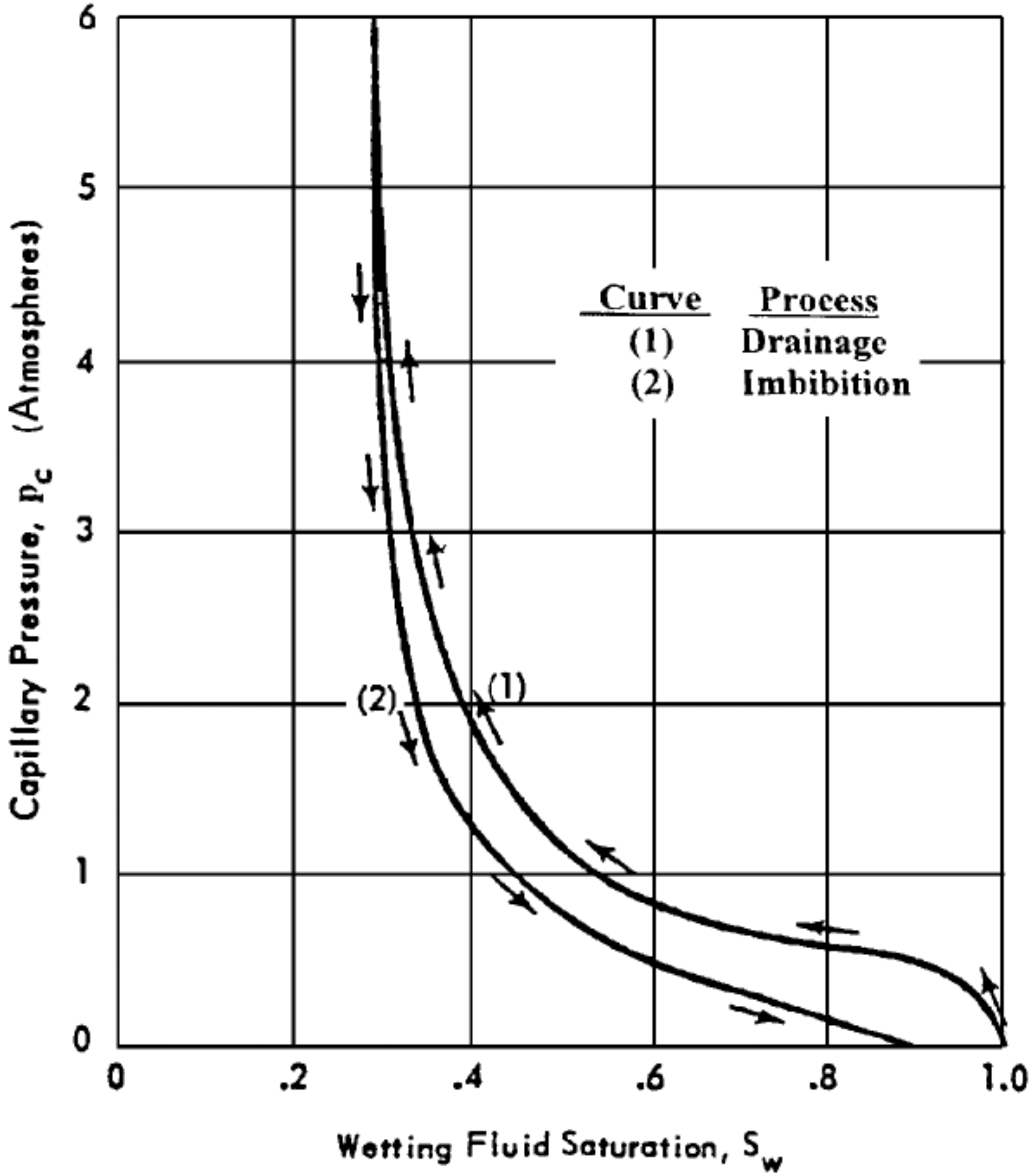

Figure 4-7. Capillary pressure hysteresis.

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- HW No. 1

threshold pressures: what is it?

"Go to the library to write some thing about it."

- HW No. 2

How you can obtained Porosity from logs? (neutron, sonic or density)

The dead line for these HWs is: Mon. 1 October, 2012

- The first quiz time is: 1 October 2012