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LABORATORIES



Modeling of Mixed-Wet Reservoir Rock

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*SPWLA Abu Dhabi Local Chapter
ADCO Auditorium – Abu Dhabi
Monday, 21st December 2009*

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Modeling of Mixed-Wet Reservoir Rock

Course title: Capillary Pressure, Hysteresis and Wettability

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Place: University of Stavanger – Stavanger, Norway

Date: Wednesday, March 11, 2009

- **Modeling**

The representation, often mathematical, of a process, concept, or operation of a system, often implemented by a computer program

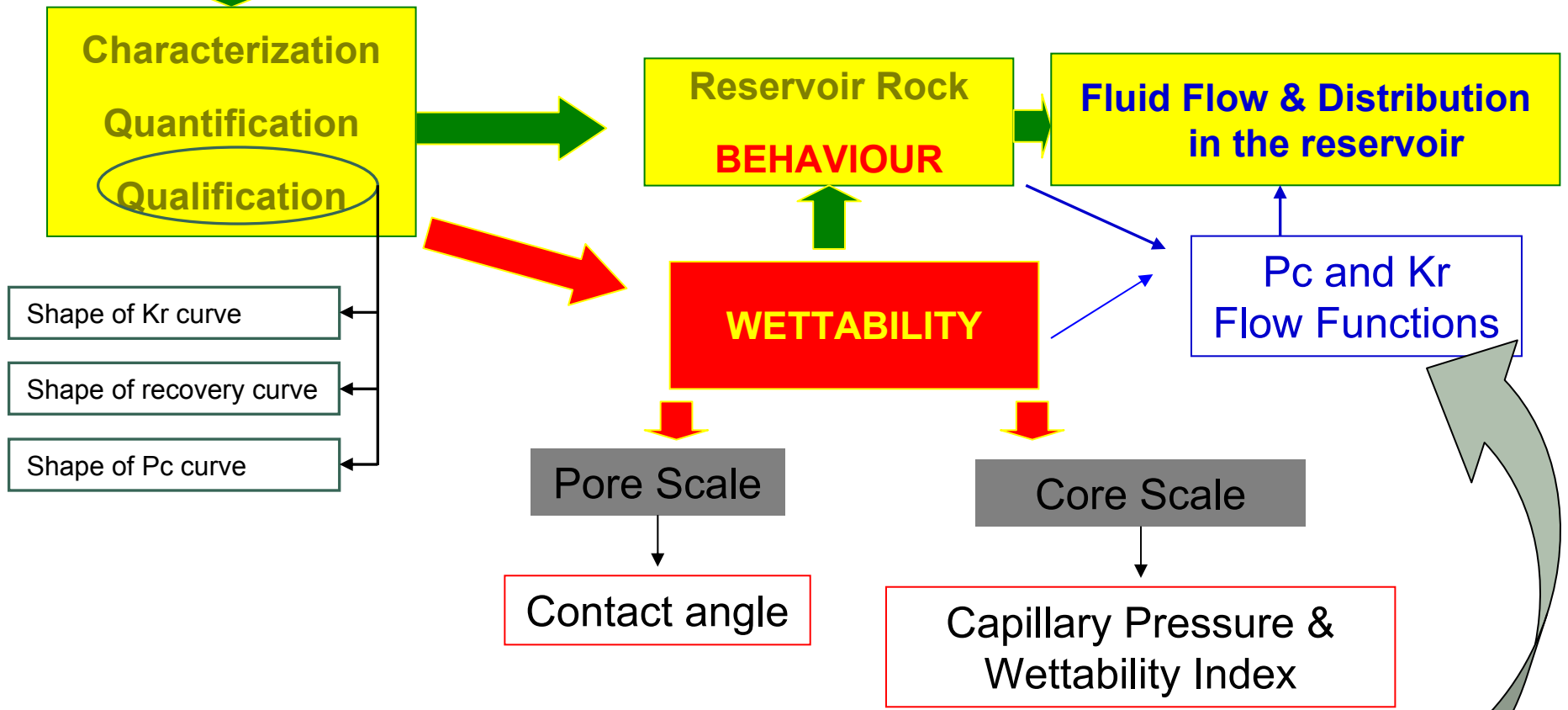
- **Mixed Wet**

Nothing was found

- **Reservoir Rock**

A rock that has sufficient porosity to contain accumulations of oil or gas

Modeling of Mixed-Wet Reservoir Rock



Understanding how Wettability is established at the pore level is crucial if predictive flow models are to be developed

- **Introduction to Wettability** (Definition, Importance, Dependence, Classification)
- **Development of Mixed Wettability in Oil Reservoirs**
- **Modeling Wettability at the Pore Scale**
- **Modeling Wettability at the Core Scale**
- **Flow Functions at the Reservoir Scale**
- **Conclusions**

- Wettability is the relative **preference of a surface** to be covered by one of the fluids under consideration (Amott, 1959)
- Wettability refers to the **tendency of one fluid to spread** on or adhere to a solid surface in the presence of immiscible fluids (Craig, 1971 or Anderson, 1986)
- The Wettability of the rock is related to the **affinity of its surface** for water and/or oil (Cuiec, 1991)
- Wettability is the overall **tendency of a reservoir rock to prefer** one fluid over another (Longeron-Hammervold-Skjaeveland, 1994)

Wettability is an important factor in all multi-phase flows:

- Residual fluid saturations and distribution
- Capillary pressure curves
- Relative permeability curves
- Electrical properties
- EOR processes

Wettability is influenced by

- Water and oil composition
- Rock mineralogy
- Temperature and pressure
- Thickness of water film

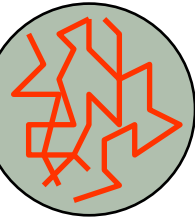
Wettability depends on

- **Rock Pore Size Distribution**
- **Rock-fluid interactions**

Classification of Wettability

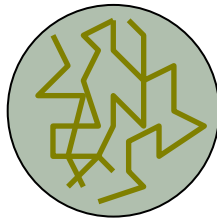
Homogeneous Wettability

Strongly oil wet

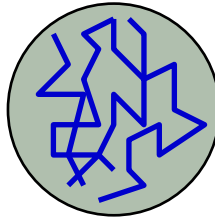


Intermediate wet

- Neutral
- Slightly oil wet
- Slightly water wet



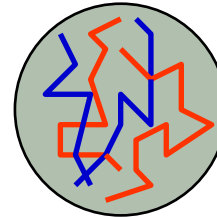
Strongly water wet



Heterogeneous Wettability

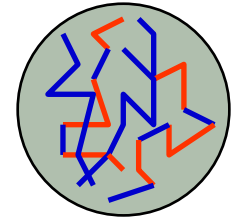
Continuous Surface type

Mixed Wettability



Non-continuous Surface type

Fractional Wettability



Homogeneous Wettability: Entire surface has the same affinity for water or oil.

Heterogeneous Wettability: Some portions of the surface have a preferential affinity for water while others have a preferential affinity for oil.

- The reservoir rock is presumed to be initially filled with water (water wet surface)
- When oil invades the rock (by capillary action), a water film is left between the surface and the invading hydrocarbon.
- Water occupies the smallest pore channels while oil tends to distribute to the largest pore channels.
- When a critical capillary pressure is exceeded the water film destabilizes and ruptures to an adsorbed molecular film of up to several water monolayers.
- Oil gets in direct contact with the rock which allows polar oil species (asphaltenes) to adsorb and/or deposit onto the rock surface. Rock wettability can be altered to mixed wet.

Thin Films

Mixed wettability can be described by considering the effects of thin films which coat and adhere to solid surfaces – Thin film forces control wettability.

- As the pressure of oil rises compared to that in the water phase, the water film tends to thin further and the oil/water curvature tends to go to zero.
- With higher oil pressure, a repulsive force arises in the water film which opposes further thinning.
- This force is called the disjoining pressure (π) and should be incorporated in the standard Young-Laplace equation.

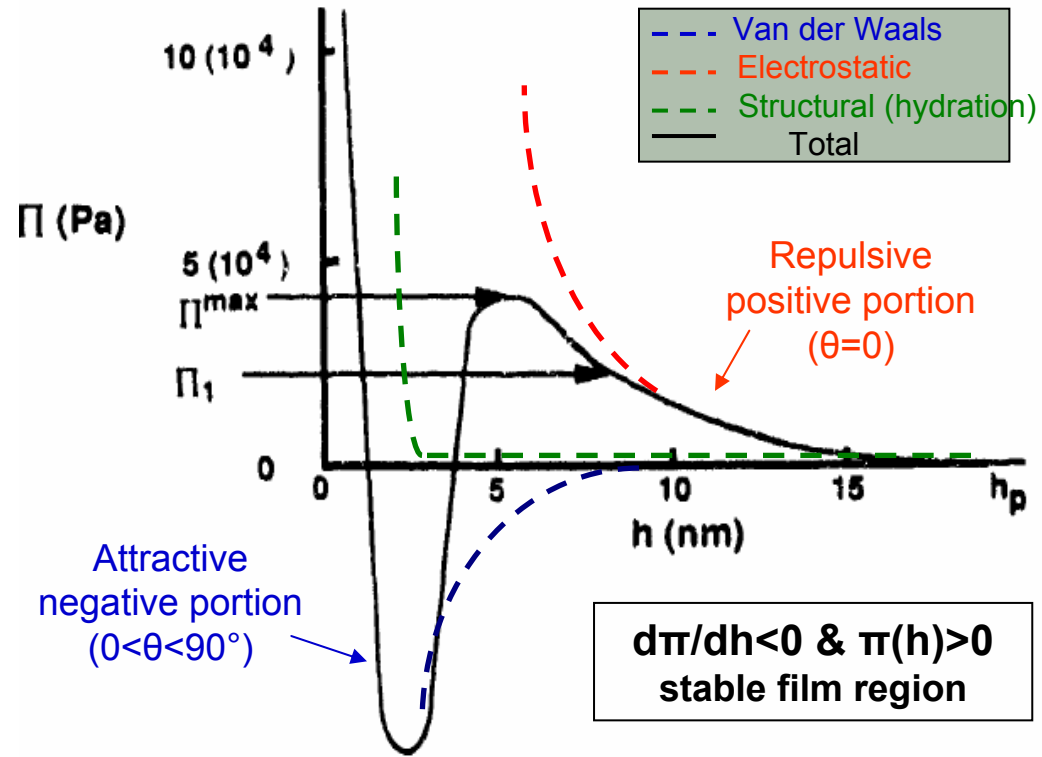
$$P_c = \sigma \left(\frac{1}{r_1} + \frac{1}{r_2} \right) + \pi(h)$$

- The π increases until it balances the capillary pressure (P_c) and the oil/water interface becomes flat.
- If the π is positive the O/W interface and the water/solid interface are repelled, whereas if the π is negative the two interfaces are attracted.

- Three major force components contribute to the shape of the disjoining pressure isotherm (Van der Waals, Electrostatic and hydration forces).
- These forces are largely influenced by the mineralogy of the rock surface.
- Contact angle is determined by the thin-film forces.
- Integration of the augmented Young-Laplace equation yields

$$\cos \theta = 1 + \frac{\int_0^{\pi(h_{eq})} h' d\Pi'}{\gamma_{\infty} \alpha \sigma}$$

This equation is derived for a meniscus attached to a solid surface and stays applicable as long as the film thickness is much smaller than the radius of curvature of the surface



Schematic disjoining pressure isotherm for wetting films on solids

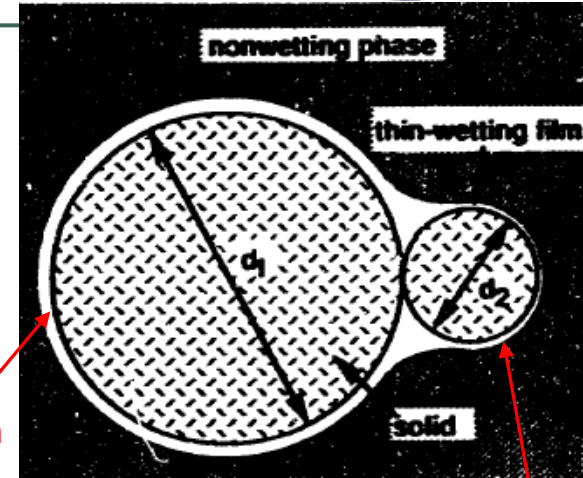
Development of Mixed Wettability in oil Reservoirs

$$P_c = \sigma \left(\frac{1}{r_1} + \frac{1}{r_2} \right) + \Pi(h) \rightarrow \Pi(h) = P_c + \frac{4\sigma}{d_s}$$

Non-zero and negative for convex curvature

Significant for thin film

To maintain equilibrium with a fixed P_c , the film disjoining pressure must rise as the diameter (d) of the solid decreases.



larger film

thinner film

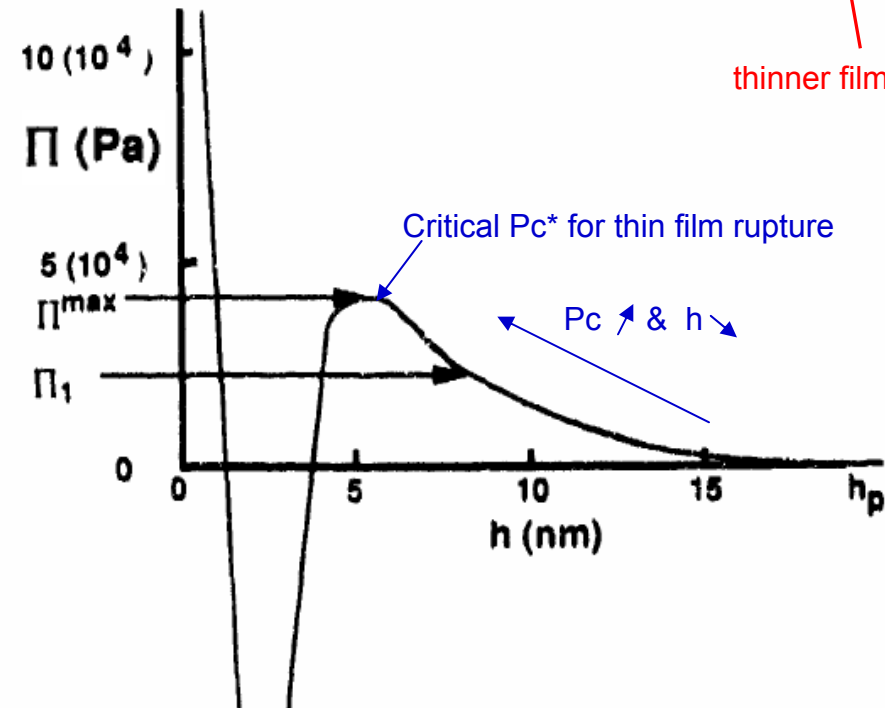
Films under imposed capillary pressure, $h/d \ll 1$

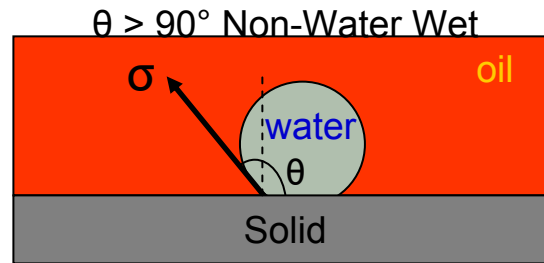
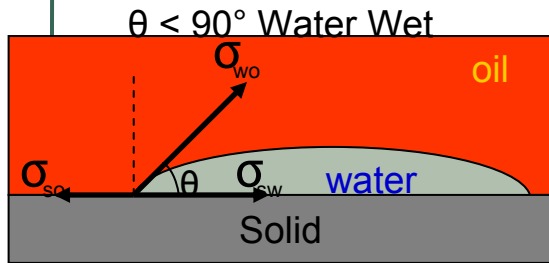
Accordingly, the film coating the smaller solid is thinner than that coating the larger solid.

➤ When the capillary pressure exceeds a critical value the water film sheets away and only a molecularly adsorbed film resides next to the solid surface.

➤ Because the disjoining pressure is largest in the film coating the smaller solid diameter, that film becomes unstable first and consequently has the smallest critical value of the capillary pressure

➤ Here asphaltenes may adsorb because only a molecular aqueous film protects the solid surface.



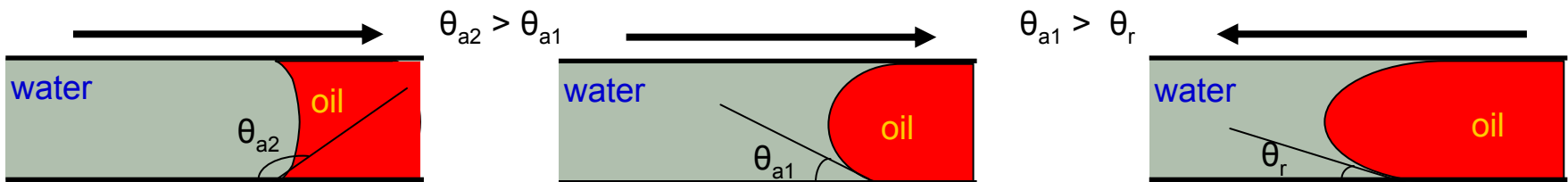


Young equation

$$\sigma_{wo} \cos \theta = \sigma_{so} - \sigma_{sw}$$

However, for a reservoir rock

- Wettability of the rock/water/oil system cannot be described by a single contact angle because it is the multitude of contact angles at the various three-phase contact regions in the pore spaces that determines the system Wettability.
- The largest and smallest among the contact angles are termed the advancing and the receding contact angles respectively. The difference between these contact angles is called **contact angle hysteresis**.



In order to describe the Wettability of the rock/water/oil system, it will be required

- To give a chemical description of the rock mineralogy, water and oil.
- To have a morphological description of the pore space with the contact angles as a boundary condition for the fluid distribution.

Wettability represents the energy lost by the system during the wetting of a solid by a liquid

$$\gamma_m = - \left(\frac{\partial G}{\partial s} \right)_{T,P}$$

OR

$$\gamma_m = \gamma_{SV} - \gamma_{SL}$$

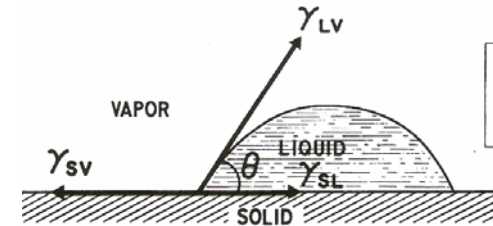
Where,

G is the free Gibbs energy,

T the temperature,

P the pressure,

S the surface area of the solid.



$$\theta \neq 0$$

$$\gamma_{sv} - \gamma_{sl} = \gamma_{lv} \cos \theta$$



$$\theta = 0$$

$$\gamma_{sv} - \gamma_{sl} \geq \gamma_{lv}$$

- If γ_m is positive, water will spread spontaneously over the solid.
- If γ_m is negative, water will contract and decrease S spontaneously
- If γ_m is zero, the configuration is stable with respect to variations in the area of the solid/water interface

If we consider the contact angle θ , then we have Young's equation

$$\gamma_{SV} - \gamma_{SL} = \gamma_{LV} \cos \theta$$

If we are able to measure directly the product $\gamma_{LV} \cos(\theta)$ (by Wilhelmy plate method for example) or γ_{LV} and $\cos(\theta)$ separately then we can determine the Wettability of the solid surface.

However, such measurements are usually done on ideal systems which cannot be transferred to actual reservoir systems.

Close look at Young's equation $\gamma_{lv} \cos\theta_Y = \gamma_{sv} - \gamma_{sl}$

- The equation indicates single contact angle (θ) which is also a unique function of the interfacial tensions. However, for real surfaces, there exists a range of contact angles which are dependent on the surface roughness and heterogeneity.
- Young's equation can be extended to describe rough (and homogeneous) surfaces by introducing roughness factor, δ

$$\gamma_{lv} \cos\theta_w / \delta = \gamma_{sv} - \gamma_{sl} \quad \text{Wenzel}$$

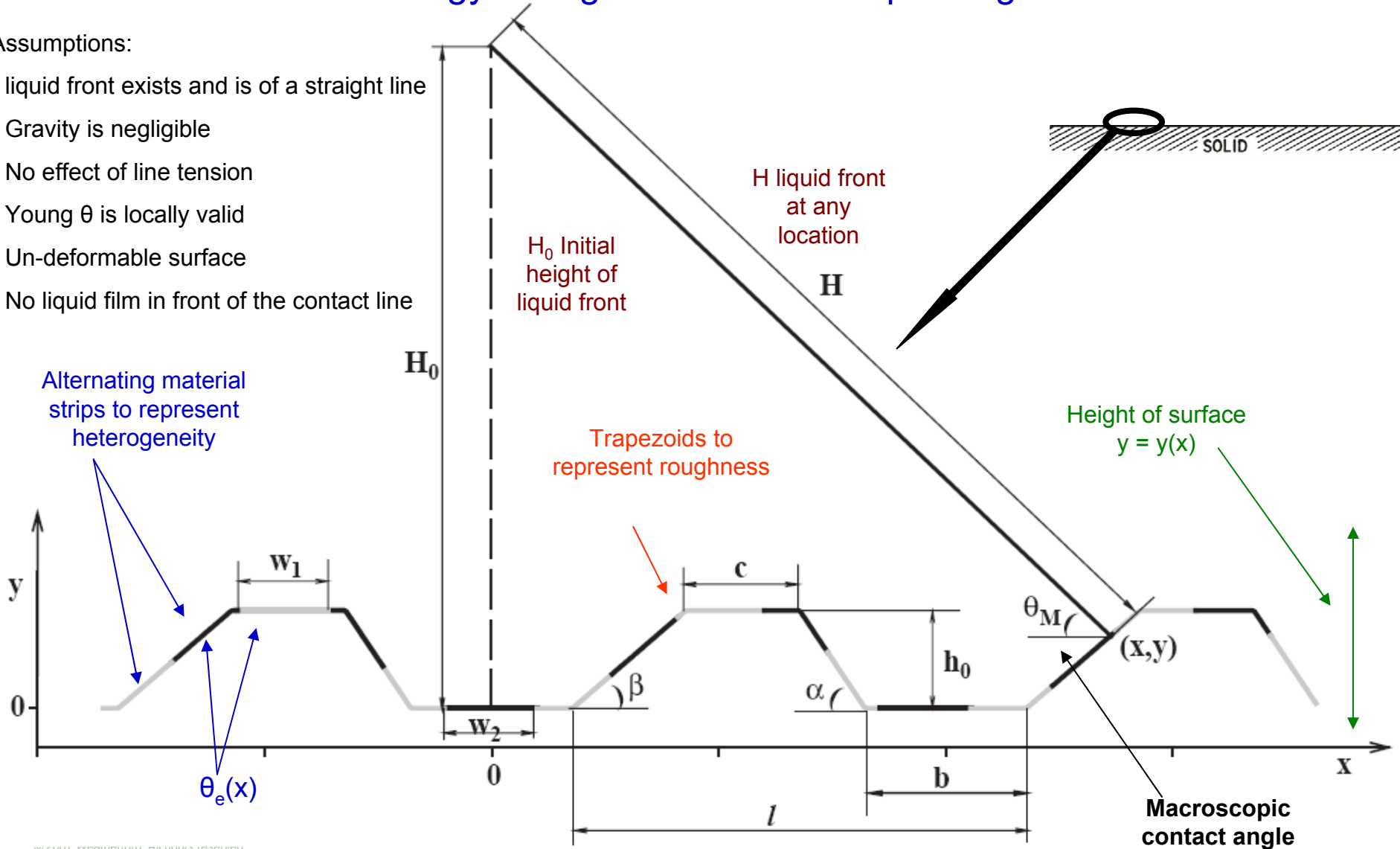
- The equation can also describe heterogeneous (and smooth) surfaces by introducing more than one intrinsic contact angle (θ_e) representing the different types of surfaces (a is the fractional surface area)

$$\cos\theta_C = a_1 \cos\theta_{e1} + a_2 \cos\theta_{e2} \quad \text{Cassie}$$

Calculation of the free energy change of a sessile drop sitting on the model surface

Assumptions:

- liquid front exists and is of a straight line
- Gravity is negligible
- No effect of line tension
- Young θ is locally valid
- Un-deformable surface
- No liquid film in front of the contact line



Calculation of the free energy change of a sessile drop sitting on the model surface

System free energy change due to movement of the liquid front \rightarrow

$$\Delta F = \Delta F_1 + \Delta F_2$$

Free energy change due to change in S / V and corresponding S / L interfacial areas

Free energy change due to change in L / V interfacial area

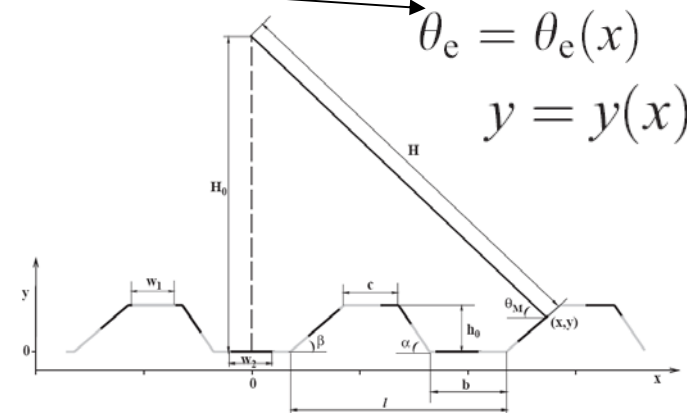
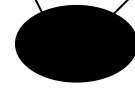
$$d(\Delta F_1) = -L(\gamma_{sv} - \gamma_{sl})ds$$

Work done on the system in replacing the S/V interface with the S/L interface

$$\gamma_{lv} \cos \theta_e = \gamma_{sv} - \gamma_{sl}$$

Young's equation (valid locally)

$$\Delta F_1 = \int_0^s -L\gamma_{lv} \cos \theta_e(x) ds$$



Calculation of the free energy change of a sessile drop sitting on the model surface

System free energy change due to movement of the liquid front \rightarrow

$$\Delta F = \Delta F_1 + \Delta F_2$$

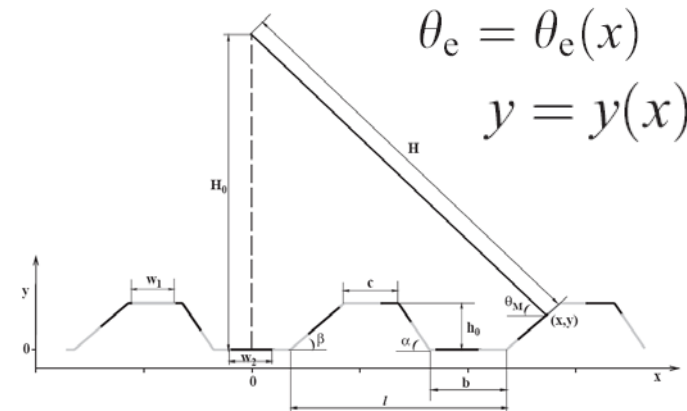
Free energy change due to change in S/V and corresponding S/L interfacial areas

Free energy change due to change in L/V interfacial area

$$\Delta F_2 = L\gamma_{lv}\Delta H \leftarrow \text{Work done on the system for expanding the liquid surface}$$

$$\Delta H = H - H_0 = \sqrt{(H_0 - y)^2 + x^2} - H_0 \leftarrow \text{Increase in liquid front length}$$

$$\Delta F_2 = L\gamma_{lv} \left(\sqrt{(H_0 - y)^2 + x^2} - H_0 \right)$$



Calculation of the free energy change of a sessile drop sitting on the model surface

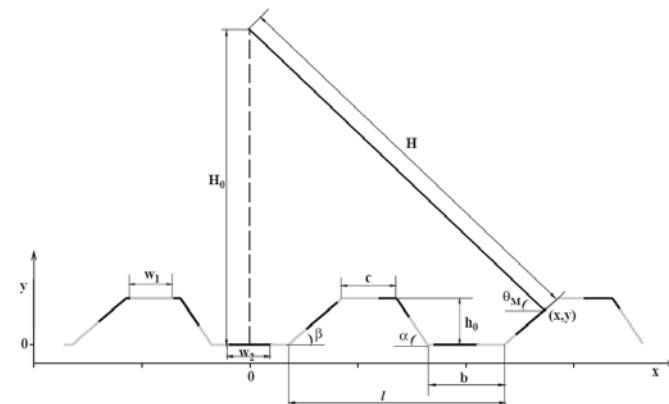
$$\Delta F = \int_0^s -L\gamma_{lv} \cos\theta_e(x) ds + L\gamma_{lv} \left(\sqrt{(H_0 - y)^2 + x^2} - H_0 \right)$$

$$\tan\theta_M = \frac{H_0 - y}{x}$$

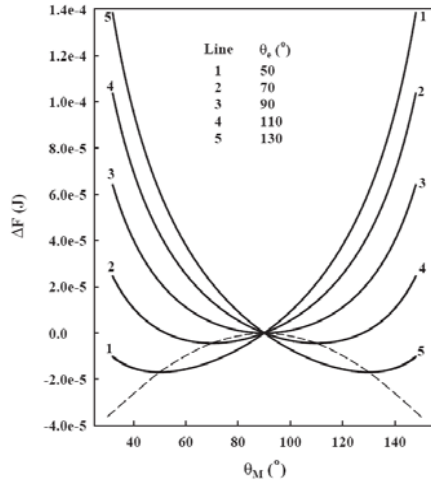
Geometric relation to correlate the system free energy change with the macroscopic contact angle

This model can be validated by computing the free energy change for several specific surfaces studied before like

- the idealized smooth and homogeneous surface
- the idealized rough but homogeneous surface
- the idealized heterogeneous but smooth surface



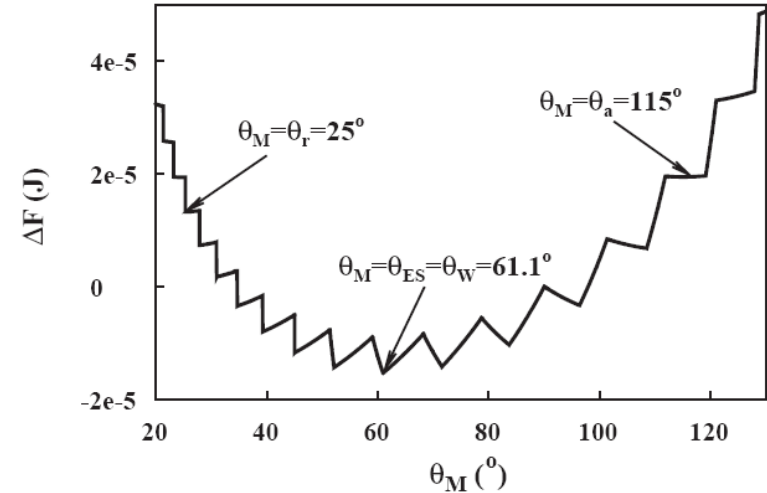
Ideal and homogeneous surfaces



Only one stable contact angle

$$\gamma_{LV} \cos \theta_Y = \gamma_{SV} - \gamma_{SL}$$

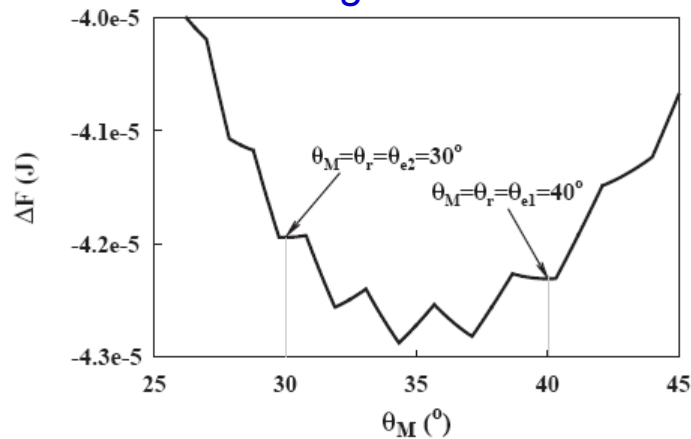
Idealized rough but homogeneous surface



- Many stable states
- $\theta_a = \theta_e + \alpha$ and $\theta_r = \theta_e - \alpha$

$$\gamma_{LV} \cos \theta_w / \delta = \gamma_{SV} - \gamma_{SL}$$

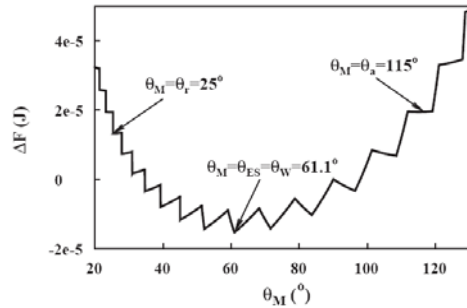
Idealized heterogeneous but smooth surface



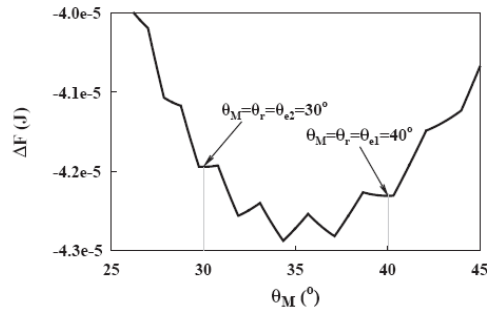
- Many local minimum points (metastable states)
- $\theta_a = \theta_{e1}$ and $\theta_r = \theta_{e1}$

$$\cos \theta_C = a_1 \cos \theta_{e1} + a_2 \cos \theta_{e2}$$

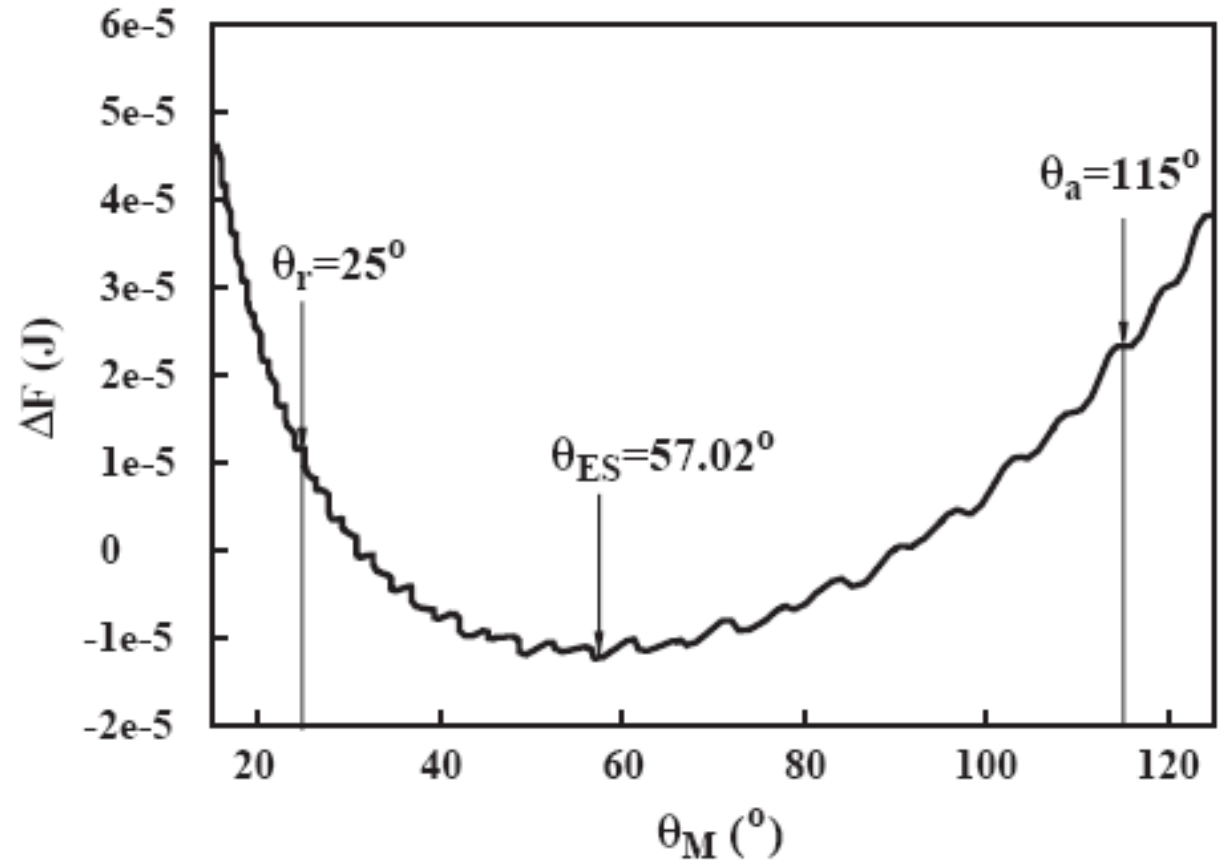
Mixed rough-heterogeneous surfaces



Rough surface



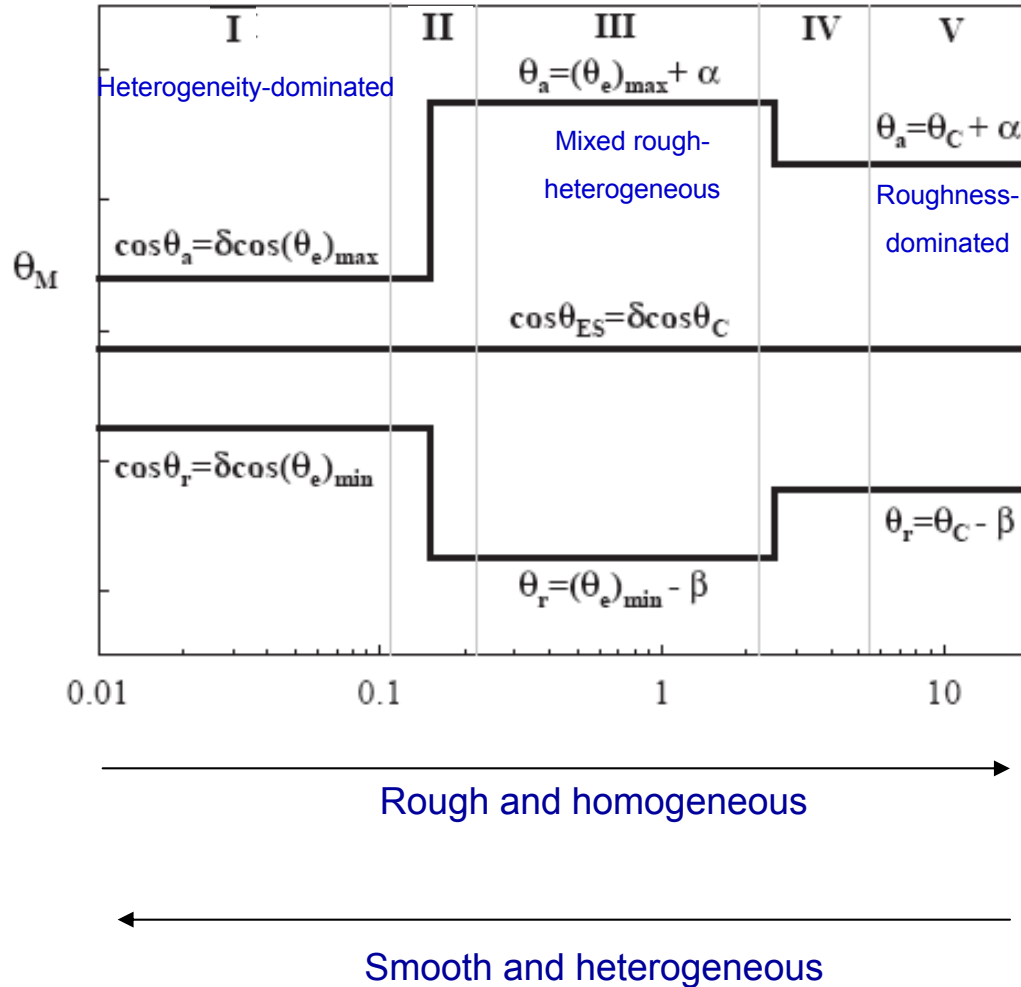
Heterogeneous surface

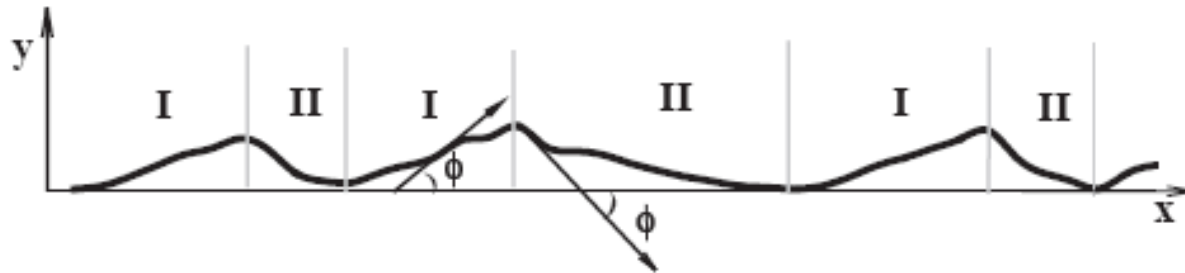


$$\theta_a = (\theta_c)_{\max} + \alpha$$

$$\cos\theta_{ES} = \delta\cos\theta_C$$

$$\theta_r = (\theta_c)_{\min} - \beta$$





For mixed rough heterogeneous surface

$$\theta_{\max} = (\theta_e)_{\max} - \phi_{\min}$$

$$\theta_{\min} = (\theta_e)_{\min} - \phi_{\max}$$

$$\Delta\theta_{H,\max} = (\theta_e)_{\max} - (\theta_e)_{\min} + \phi_{\max} - \phi_{\min}$$

This equation shows that both the maximum and minimum intrinsic contact angles and the surface topography will determine the upper limit of the contact angle hysteresis.

- In practice, surfaces within porous reservoir rock are curved, heterogeneous and rough. Hence, it is difficult to measure contact angles and to determine the extent of connectivity of water and oil wetting surfaces.
- As an alternative, contact angles can be derived by scaling equations from capillary pressure curves (for uniformly wetted media)

$$P_{c1}(\bar{S}) = \frac{\sigma_1 \cos(\phi_1^{A,R})}{\sigma_2 \cos(\phi_2^{A,R})} P_{c2}(\bar{S}) = \beta P_{c2}(\bar{S})$$

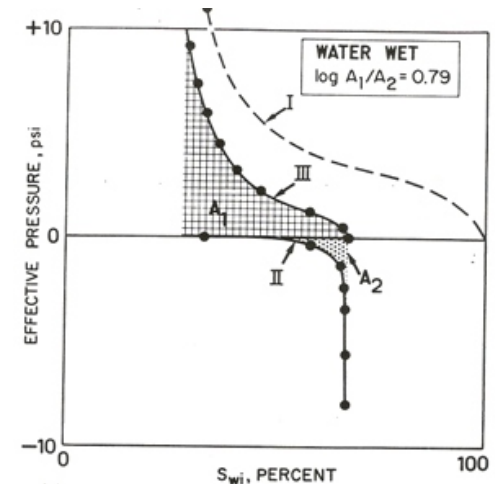
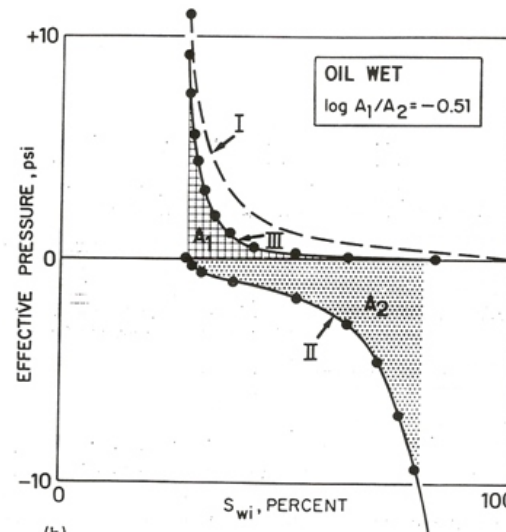
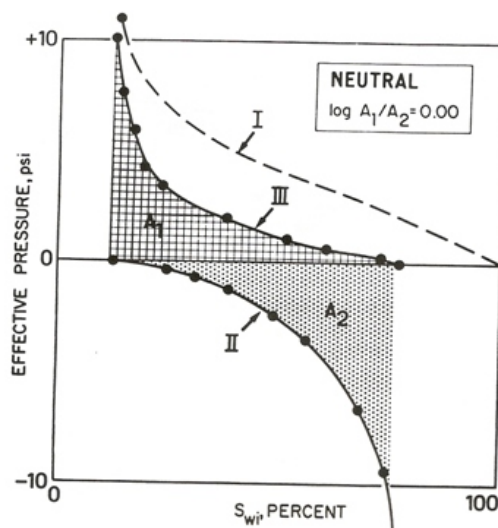
where the effective saturation \bar{S} is given by $(S - S_r)/(1 - S_r)$ with S_r as the residual saturation.

If $\phi_2^{A,R}$ is assumed to be zero, then $\cos(\phi_1^{A,R})$ can be estimated as $\cos(\phi_1^{A,R}) = (\sigma_2/\sigma_1)\beta$

- Capillary pressure as a function of water saturation exhibits characteristic shapes for different types of Wettability in porous media.
- There is also the possibility of correlating wettability with the area of the hysteresis loop or other areas between the capillary pressure curve and the saturation axis.

Capillary pressure curves (USBM) are employed in evaluating Wettability. The method is based on correlating the degree of wetting to the areas under the Pc curves which are in turn connected to the variation in the free energy of the system

- Pc curves depend on Wettability and pore size distribution
- For water wet system $\log(A_1/A_2)$ is positive. For oil wet is negative and around zero for neutral system
- The ratio of the areas may be assumed independent of the pore geometry of the system. Thus A_1/A_2 can be viewed as a quantitative Wettability scale.
- With comparison with the Amott test both Amott test and the Pc test may not give similar Wettability information for non-water systems



Imbibition and Displacement Experiments (Amott)

Core material is at Sor

Volume V1: Spontaneous drainage to oil (water displaced by oil)

Volume V2: Secondary drainage to oil by centrifuge (single point)

Volume V3: Spontaneous imbibition of water

Volume V4: Forced water imbibition by centrifuge (single point)

$$I_o = V1/(V1+V2), I_w = V3/(V3+V4), WI = I_o - I_w$$

For oil wet samples, $I_o > 0$ and $I_w = 0$. Implies positive WI indicates oil wetness while negative WI indicates water wetness. When $WI = 0$ then intermediate Wettability.

Comments:

- The ratios defined are mainly dependent on Wettability
- Easy to interpret the results
- Test is fast and easy to perform

Imbibition and Displacement Experiments (Amott-IFP)

- SAMPLE SATURATED WITH OIL AND BRINE (at S_{WR}).
- STAGES OF THE TEST:

• IMBIBITION IN BRINE	→	A	OIL RECOVERED
• DISPLACEMENT BY BRINE	→	B	OIL RECOVERED
• IMBIBITION IN OIL	→	C	BRINE RECOVERED
• DISPLACEMENT BY OIL	→	D	BRINE RECOVERED
- WETTABILITY INDEX:

$$WI = A/A + B - C/C + D$$
- WETTABILITY SCALE ADOPTED:

WI	-1	-0.3	-0.1	+0.1	+0.3	+1
		Slightly oil wet	Neutral	Slightly water wet		
WETTABILITY	OIL WET	INTERMEDIATE		WATER WET		

- Wettability is expressed by WI
- Results must be interpreted with care. For example, $WI1 = 0.65 - 0.25 = +0.4$ compared to another $WI2 = 0.4 - 0 = +0.4$, apparently do not have the same Wettability properties.
- WI1 case may indicate heterogeneous Wettability with water wet dominance. WI2 may indicate spotted wettability with isolated oil wet surfaces
- The results might be influenced by gravity especially if rock perm is high or when the IFT is low

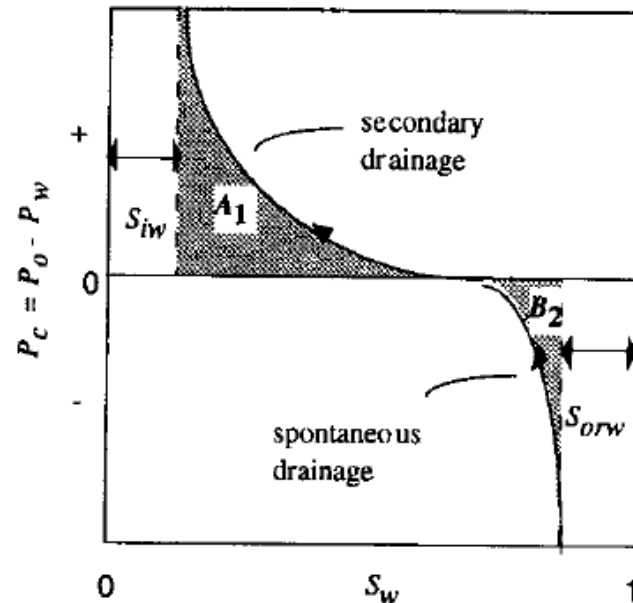
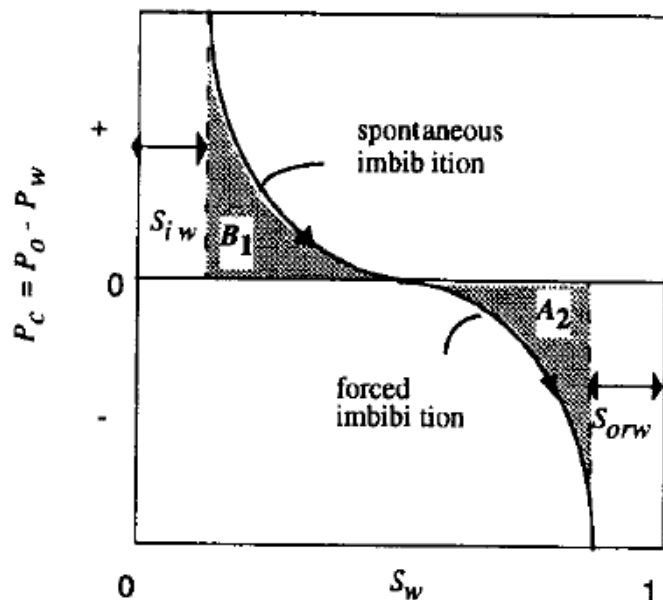
Extension of the Amott test (Improvement of USBM)

- Incorporate all four areas between Pc curves and Sw axis
- Better discrimination between mixed-wet and spotted-wet systems
- Hammervold-Longereon index I_{HL} includes spontaneous imbibition and drainage processes in a new Wettability Index

$$I_w = B_1 / (B_1 + A_2)$$

$$I_o = B_2 / (B_2 + A_1)$$

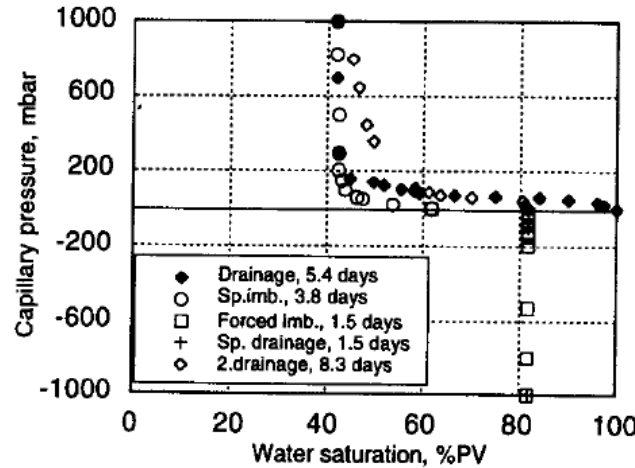
$$I_{HL} = I_w - I_o$$



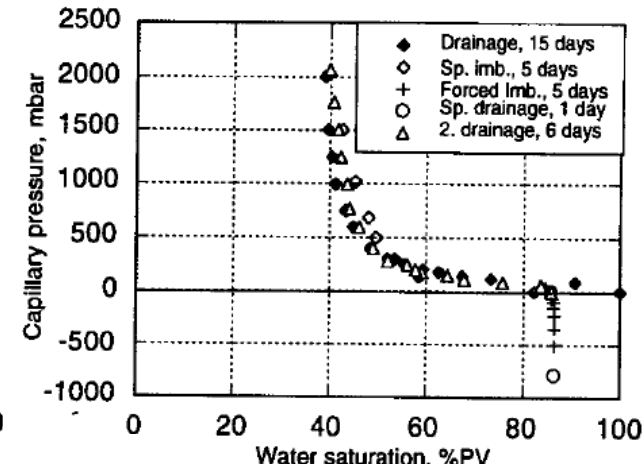
The new index was validated thru P_c measurements on sandstone and carbonate cores for each rock type on water wet core and aged core in crude oil.

The areas were calculated by a computer program using the measured data.

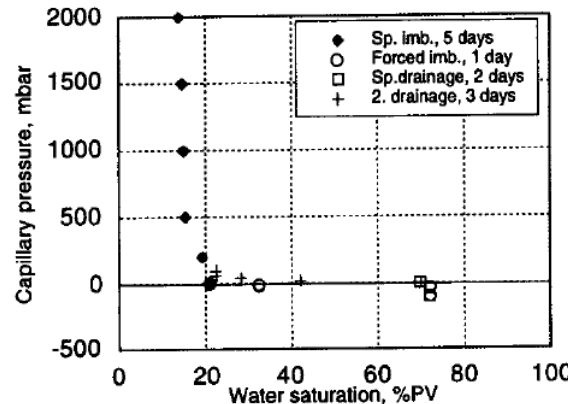
The USBM and Amott indices were also calculated from the data to compare with the new index.



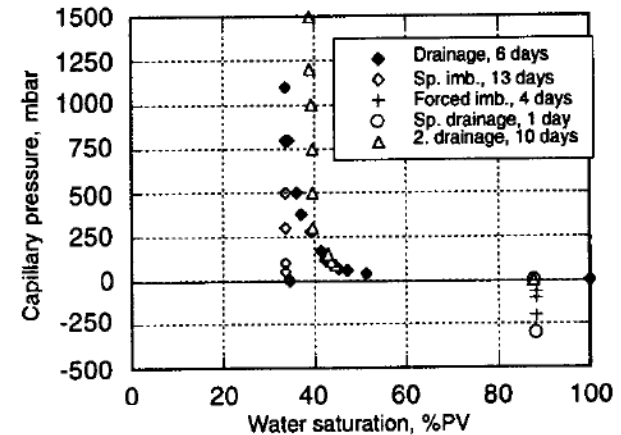
P_c loop (test No.1), Vosges sandstone, water-wet, $I_{HL} = 0.85$.



P_c loop (test No.3), carbonate core, water-wet, $I_{HL} = 0.97$.



P_c loop (test No.2), Vosges sandstone, aged in crude oil, $I_{HL} = 0.65$.



P_c loop (test No.4), carbonate core, aged in crude oil, $I_{HL} = -0.01$.

- Capillary pressure is the driving force that controls oil migration into the reservoir, and hence, controlling the fluid distribution along the height of the reservoir down to the free water level.
- Capillary pressure is again the main driving force that controls the fluid distribution during water imbibition and gas injection processes.
- Therefore, it is of great importance to have a capillary pressure function (model) to properly predict displacement processes by numerical simulation models.
- Most oil reservoirs are no longer viewed as water wet and hence the capillary pressure function should be representative to varying Wettability in the reservoir.

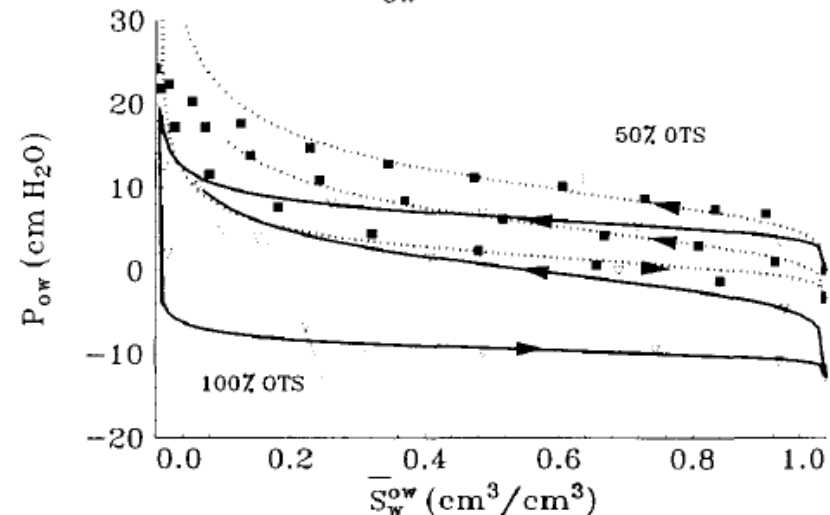
- For a water wet core (positive curve) the following empirical model can be applied (Van Genuchten, 1980).

$$P_{ow} = \frac{1}{\alpha} \left[(S_w^{ow})^{n/(1-n)} - 1 \right]^{1/n} \quad \text{where } n \text{ and } \alpha \text{ are empirical parameters}$$

- To account for both positive and negative capillary pressures, the model was modified as follows (Bradford and Leij, 1995)

$$P_{ow} + \gamma = \frac{1}{\alpha} \left[(\bar{S}_w^{ow})^{n/(1-n)} - 1 \right]^{1/n}$$

The parameter γ was set equal to the magnitude of the lowest observed P_{ow}



- For a water wet core (positive curve) the following power law correlation can be applied (Brooks and Corey, 1964).

$$P_{cd} = \frac{c_{wd}}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_{wd}}} \quad \text{where } c_{wd} \text{ is the entry pressure, } 1/a_{wd} \text{ the poresize distribution index, } S_{wr} \text{ the residual (irreducible) water saturation.}$$

- For oil wet core similar correlation can be applied by simply changing index “w” to “o”.

$$P_c = \frac{c_o}{\left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^{a_o}}$$

- To obtain a correlation which satisfies the in between wettability limits we can sum the water wet and the oil wet branches (Skjaeveland, 1998)

$$P_c = \frac{c_w}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_w}} + \frac{c_o}{\left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^{a_o}}$$

Can this correlation be used to predict fluid distribution in the reservoir with varying Wettability?

Plots produced by the capillary pressure correlation – Bounding and hysteresis scanning curves

$$p_c = \frac{c_w}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_w}} + \frac{c_o}{\left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^{a_o}}$$

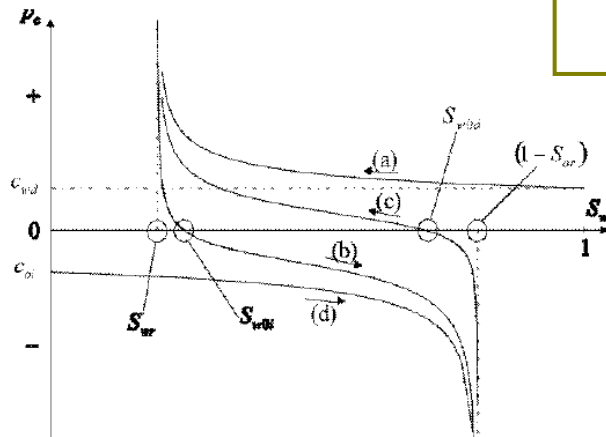


Fig. 1—Schematic of bounding curves: (a) primary drainage; (b) (secondary) imbibition; (c) secondary drainage; (d) primary imbibition.

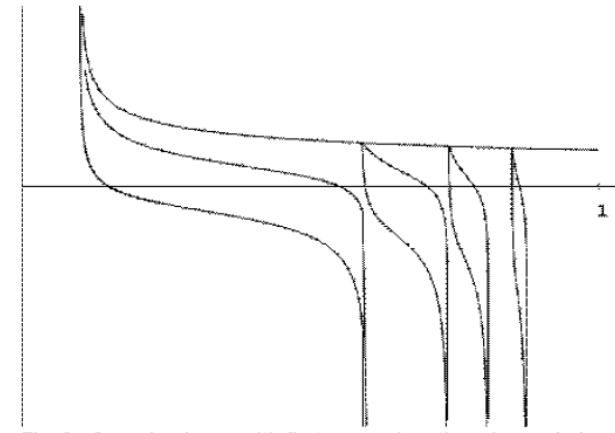


Fig. 2—Scanning loops with first reversal on the primary drainage curve and second reversal at the respective residual oil saturation.

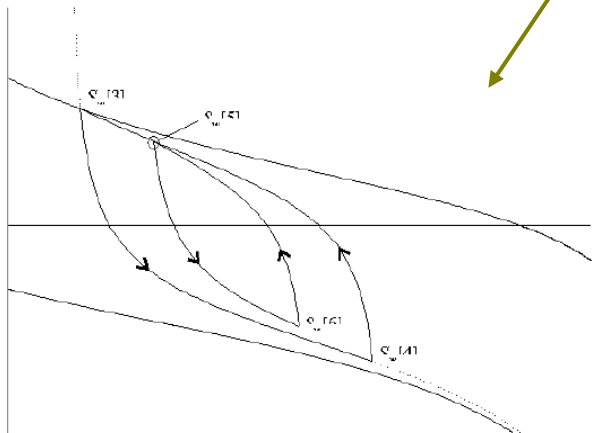


Fig. 3—A family of scanning loops spawned from a reversal point on the secondary drainage bounding curve.

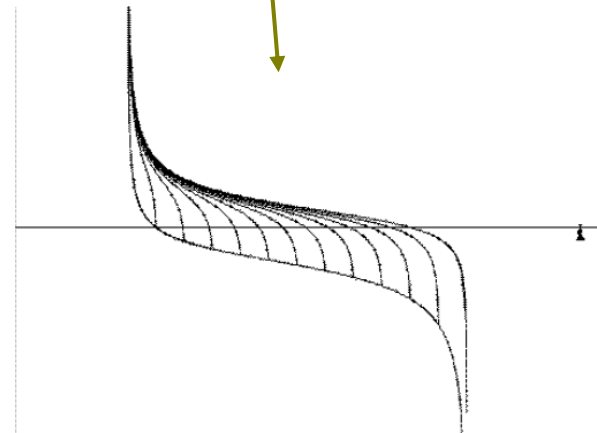


Fig. 4—Series of drainage scanning curves initiated at different reversal points on the imbibition bounding curve.

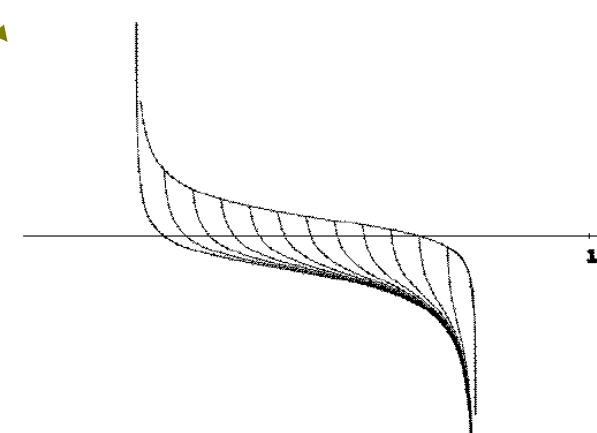


Fig. 5—Series of imbibition scanning curves initiated at different reversal points on the secondary drainage bounding curve.

Plots produced by the capillary pressure correlation – Bottom-Water Drive

$$p_c = \frac{c_w}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_w}} + \frac{c_o}{\left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^{a_o}}$$

The capillary pressure correlation was also used to manufacture a scanning imbibition curve upon the upward movement of the FWL during reservoir oil production.

Reservoir Scale

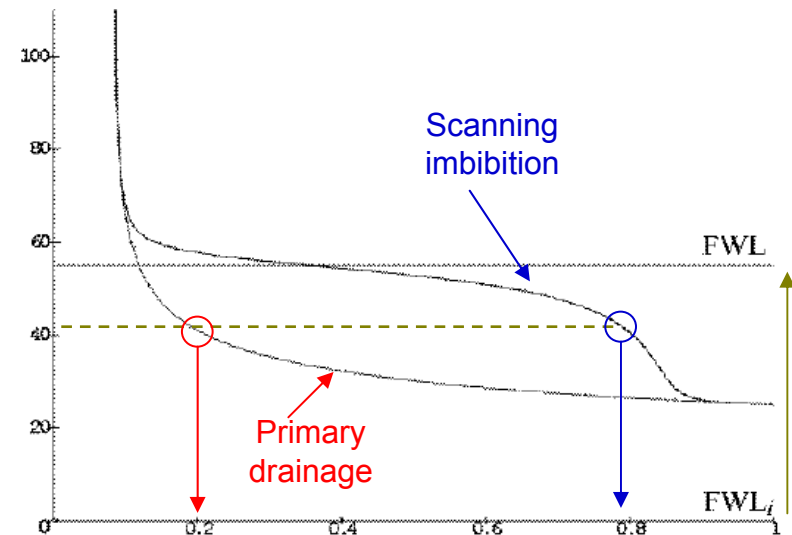


Fig. 6—Height above free water level (FWL) as a function of water saturation for two values of FWL; transition from a primary drainage curve at FWL_i over to an imbibition dominated curve at FWL .

The curve fitting was done on two fresh cores for imbibition and secondary drainage

Summarized procedure:

1. For imbibition the oil branch of the correlation dominates (i.e. $C_w \sim \text{zero}$). Therefore, $\log(-P_c)$ vs. $\log((S_o - S_{or})/(1 - S_{or}))$ yields estimates of C_{oi} and a_{oi}
2. C_{wi} and C_{od} are estimated by setting $P_c=0$ for the main correlation water branch and oil branch respectively.
3. It is first assumed $a_{oi} = a_{od}$ and also $a_{wi} = a_{wd}$
4. The total error is determined by summing the errors squared between measured P_c and correlation. The errors are weighed by the factor $(1/P_c)^2$. The error is then simultaneously minimized with respect to a_o , a_w , c_{oi} & c_{wd} by a standard optimization package, and c_{od} & c_{wi} are calculated as in point 2 above.

$$p_c = \frac{c_w}{\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{a_w}} + \frac{c_o}{\left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^{a_o}}$$

Curve fitting of Centrifuge Bounding Curve Data

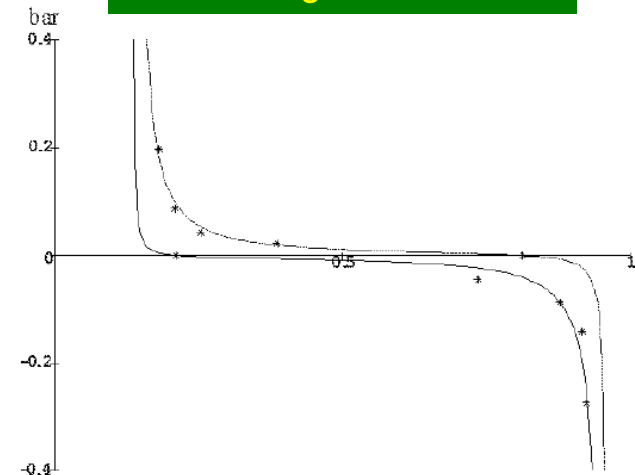


Fig. 7—Capillary pressure correlation fitted to forced imbibition and forced drainage centrifuge data from special core analysis.

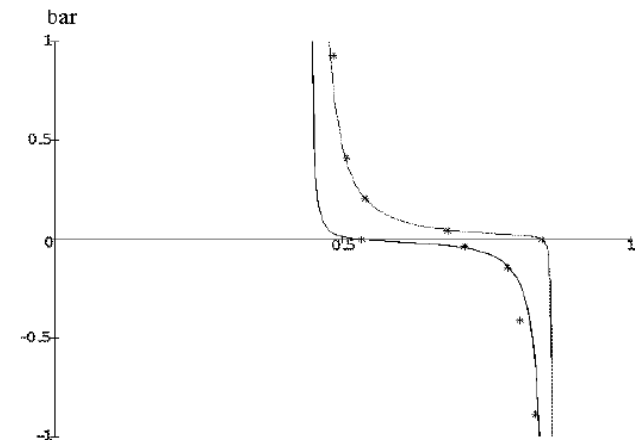


Fig. 8—Capillary pressure correlation fitted to forced imbibition and forced drainage centrifuge data for another core.

The Pc correlation models the experiments satisfactorily (oil wet fresh cores)

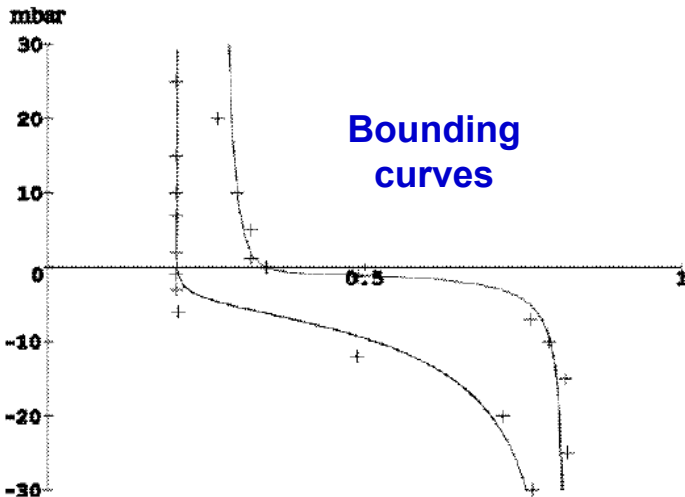


Fig. 13—Predicted bounding curves and measured data.

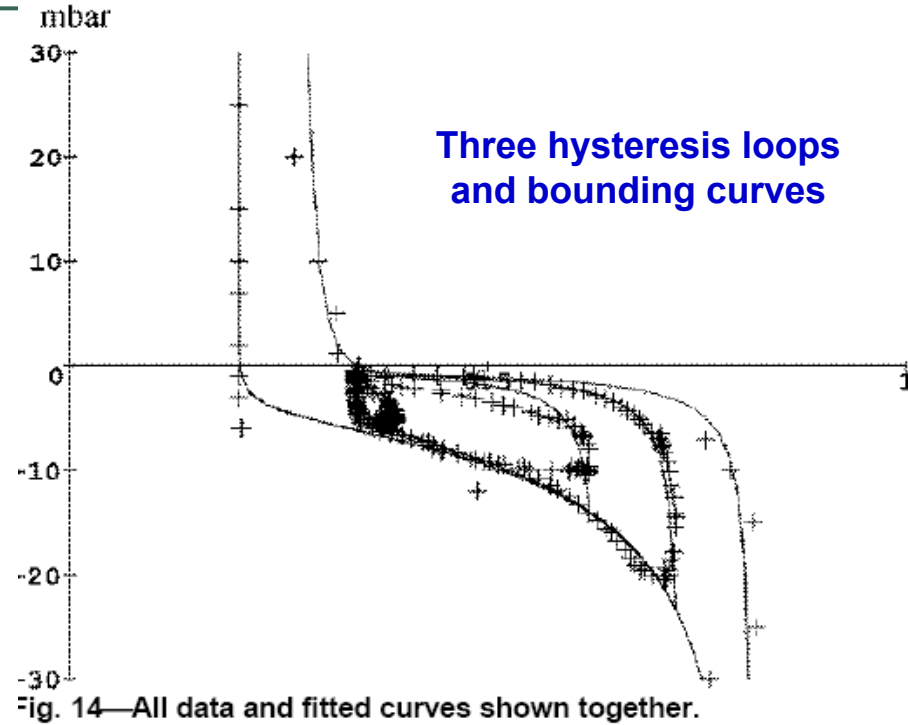


Fig. 14—All data and fitted curves shown together.

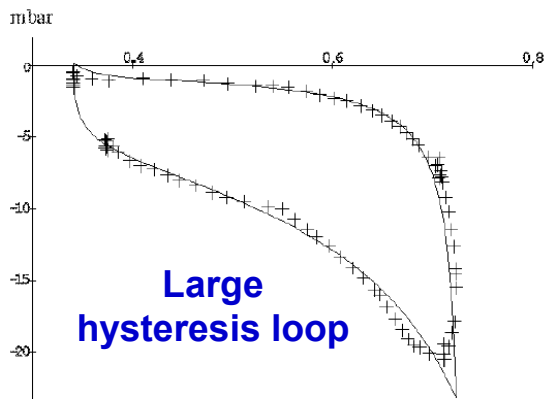


Fig. 9—Capillary pressure correlation fitted to the large scanning loop data.

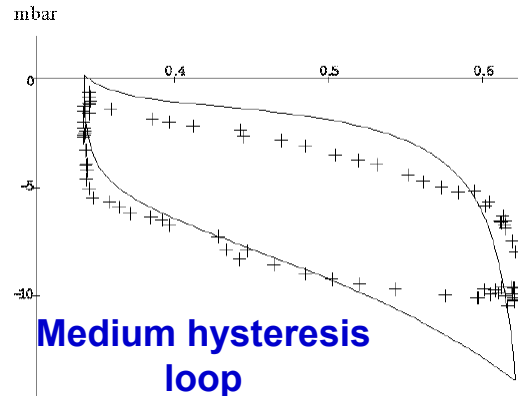


Fig. 10—Predicted medium scanning loop and measured data.

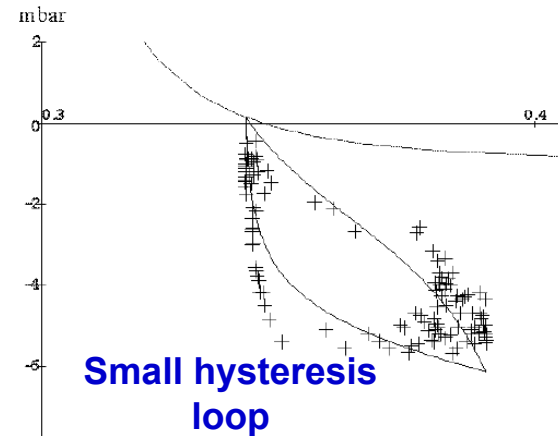


Fig. 11—Predicted small scanning loop and measured data.

Sandstone Reservoir in the North Sea

With all parameters fixed (except FWL which was adjusted separately), the saturation distribution with height was predicted by the Pc correlation

Although there is a wide spread in the data, the correlation fairly well predicts the rise of the water table

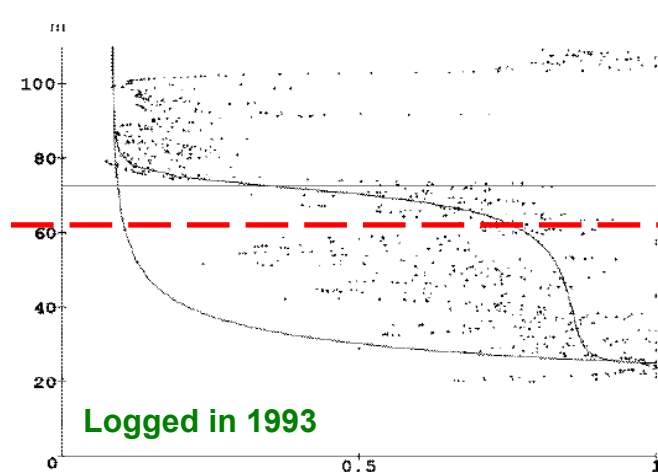


Fig. 18—Height above the free water level in 1993 as a function of water saturation, well data and prediction by correlation, transition from primary drainage to imbibition bounding curve.

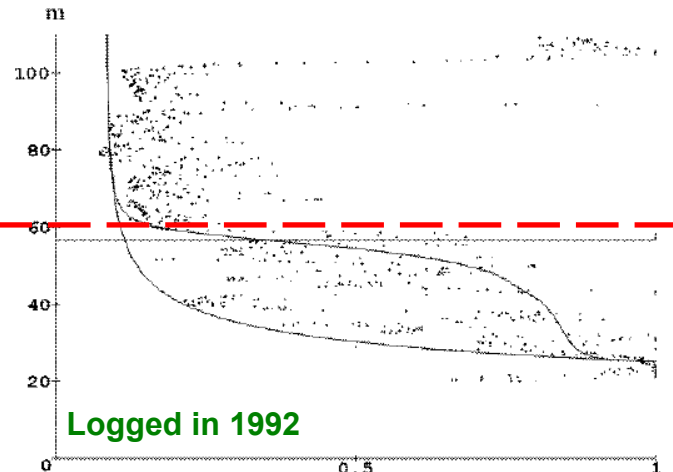


Fig. 17—Height above the free water level in 1992 as a function of water saturation, well data and prediction by correlation, transition from primary drainage to imbibition bounding curve.

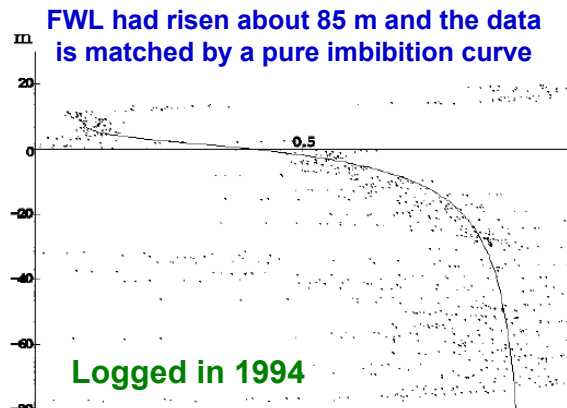


Fig. 16—Height above the free water level in 1994 as a function of water saturation, well data and fitted correlation, imbibition bounding curve.

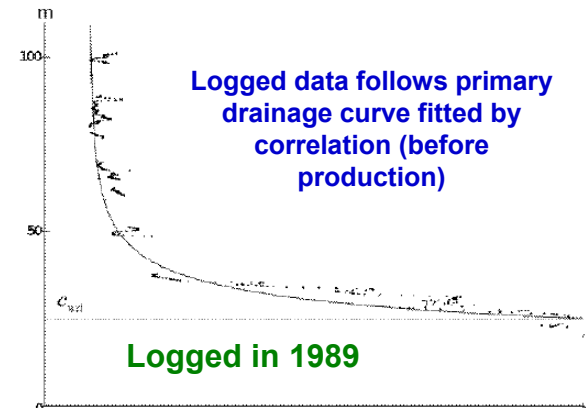


Fig. 15—Height above the free water level as a function of water saturation, well data and fitted correlation, initial conditions, primary drainage.

- The aim of Wettability modeling of a reservoir porous medium is to predict reservoir behavior by predicting fluid flow and distribution.
- Modeling Wettability at the pore scale (by contact angle) is difficult and should include surface properties such as irregularity, roughness and heterogeneity.
- Modeling Wettability at the pore scale (by thin film) is also difficult and should include the disjoining pressure isotherm which is a resultant of intermolecular forces between the interfaces.
- However, current modeling at the pore scale (contact angle or thin film) cannot give direct evaluation of the reservoir rock system Wettability.
- The core scale model of Wettability is based on experimental evaluation of the Pc curves and WI values. It can give good differentiation of Wettability between different core material but again cannot be used directly in predicting reservoir flow behavior.
- Flow functions (e.g. Pc correlations) which are validated on core samples can be used in simulation models to predict the reservoir behaviour.
- Those flow functions are empirical but surely could be derived from the huge modeling work already executed at the pore and core scales.

Thank you