Capillary Pressure and Apparent Tensile Rock Strength during Drainage and Imbibition

Alexander Rozhko, *Ph.D*

M-I SWACO a Schlumberger Company

Stavanger, Norway

Email: arozhko01@slb.com

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Introduction

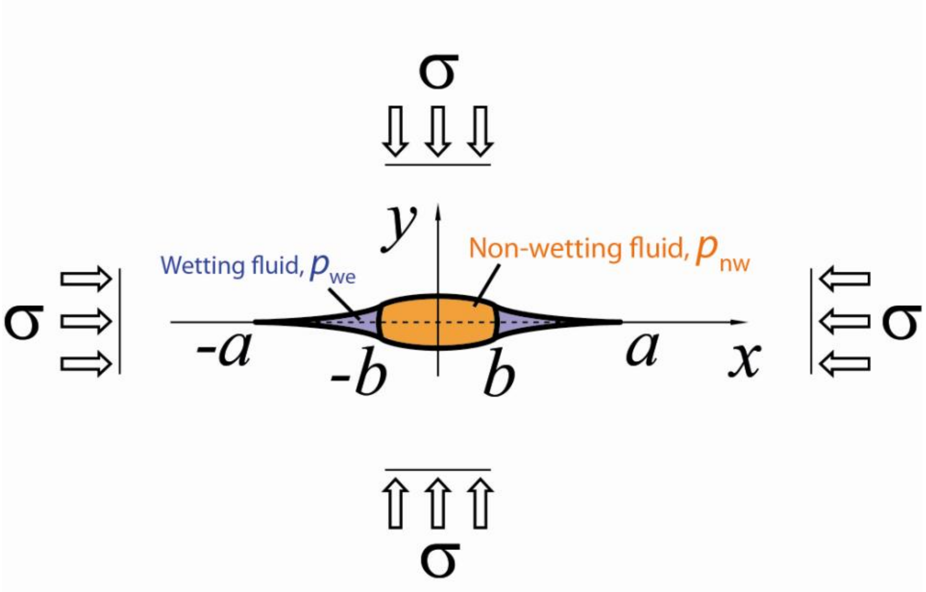
- Wellbore stability problems occur when near-wellbore stresses exceed the rock strength.
- Drilling fluids, penetrating into a formation are able to change significantly the strength of rock around the borehole.
- The penetration of borehole fluids into the formation is driven by fluid pressure gradients, by capillary suction and by osmotic suction.
- Understanding and predicting how various fluids, entering into the formation, are able to change the strength of rock is important for design of appropriate mud weight window during drilling operation, to reduce the wellbore stability problems.

Mechanisms of fluid/rock interaction, causing the change of rock strength

- Effect of water activity [*Van Oort et al.*, 1995; *Chenevert and Amanullah*, 1997; *Horsrud et al.*, 1998]. The osmotic diffusion, driven by difference of water activity in the rock and surrounding fluid is typical for clay bearing rocks (such as shale, claystones, shaly sandstones, etc.), because clays are the membranes in osmotic process [*Fritz*, 1986].
- Pressure solution effect [*Hellman et al.*, 1996], which can be important over long geological time scale [*Risnes et al.*, 2003].
- Stress corrosion effect that has been observed in sandstones [*Hadizadeh and Law*, 1991].
- Crack lubrication [*Van Eeckhout*, 1976; *Grgic et al.*, 2005].
- Chemical reactions between water and rock [*Han*, 2003].
- Decrease of surface fracture energy (Rehbinder effect).
- Decrease of effective stress due to pore pressure increase.
- Capillary phenomenon.

New model to study effects of capillary force on rock strength

A new crack-based approach is suggested, which has the following advantages over standard grain-based approach :



✓**Crack-based approach is clearly more sensible for more compacted or denser rocks, where the pore space is not predominantly the spaces between grains.**

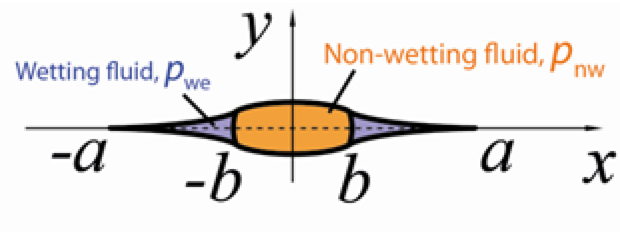
✓**The crack-based approach is applicable for the whole range of saturation for wetting fluid from 0% to 100%, while the grain-based approach is applicable only for the range 0%-25% of saturation.**

✓**Using the crack-based approach it is possible to explain the difference of capillary pressure during drainage and imbibition conditions (observed in rocks and soils), while, to my knowledge, it is too difficult to explain the hysteresis with grain-based approach.**

Outline of crack-based model:

❑ **According to Griffith's theory the strength of material is controlled by strength concentrations on tips of preexisting microfractures.**

❑**To calculate the capillary pressure and predict its effect on strength, both the fracture geometry and stress concentrations has been calculated for different locations of interface meniscus within the fracture (*i.e.* for different *b*).**



Calculations are based on Method of Complex Potentials [*Muskhelishvili*, 1977]:

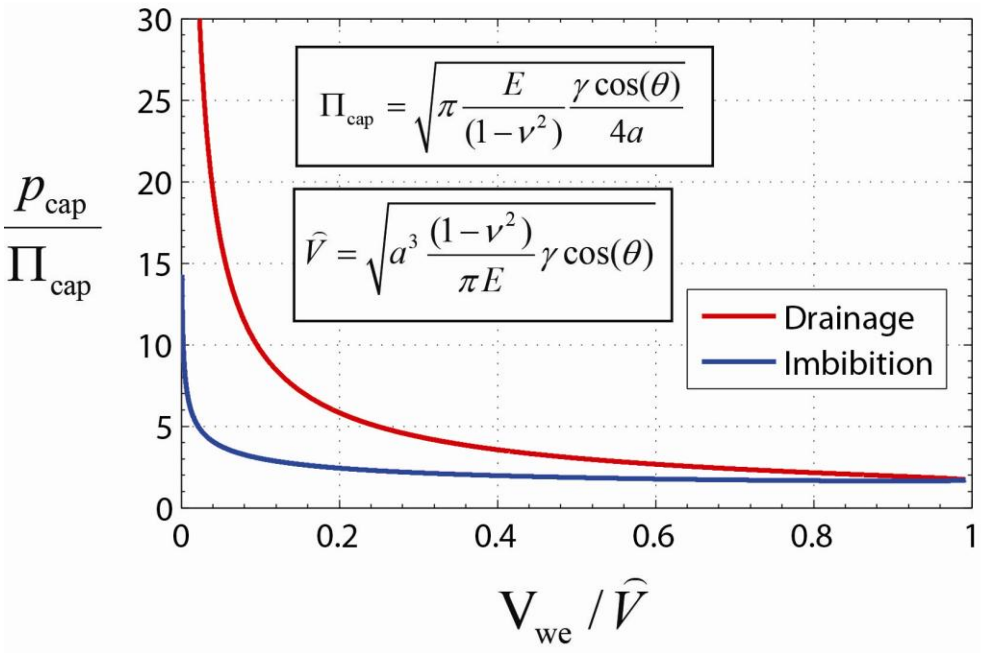
$$\sigma_{xx} + \sigma_{yy} = 4\,\mathrm{Re}\left[\frac{\varphi'(\zeta)}{\omega'(\zeta)}\right],$$

$$\sigma_{yy} - \sigma_{xx} + 2i\sigma_{xy} = 2\,\frac{\overline{\omega(\zeta)} - \omega(\zeta)}{\omega'(\zeta)}\,\frac{\partial}{\partial\zeta}\left(\frac{\varphi'(\zeta)}{\omega'(\zeta)}\right),$$

$$\frac{E}{1+\nu}(u_x + iu_y) = (3-4\nu)\varphi(\zeta) + \left(\overline{\omega(\zeta)} - \omega(\zeta)\right)\frac{\overline{\varphi'(\zeta)}}{\overline{\omega'(\zeta)}} - \overline{\varphi(\zeta)}$$

Capillary pressure curves during drainage and imbibition

During **drainage** the volume of wetting fluid inside the fracture(=representative volume) is **decreased**, while during **imbibition** the volume of wetting fluid inside the crack is **increased.**



Capillary pressure curves during drainage and imbibition, as a function of volume of wetting fluid inside the crack

Where:

$\frac{p_{cap}}{\Pi_{cap}}$ = Dimensionless Capillary Pressure

$\frac{V_{we}}{\hat{V}}$ = Dimensionless Volume of Wetting Fluid

γ = Interface tension between immiscible fluids

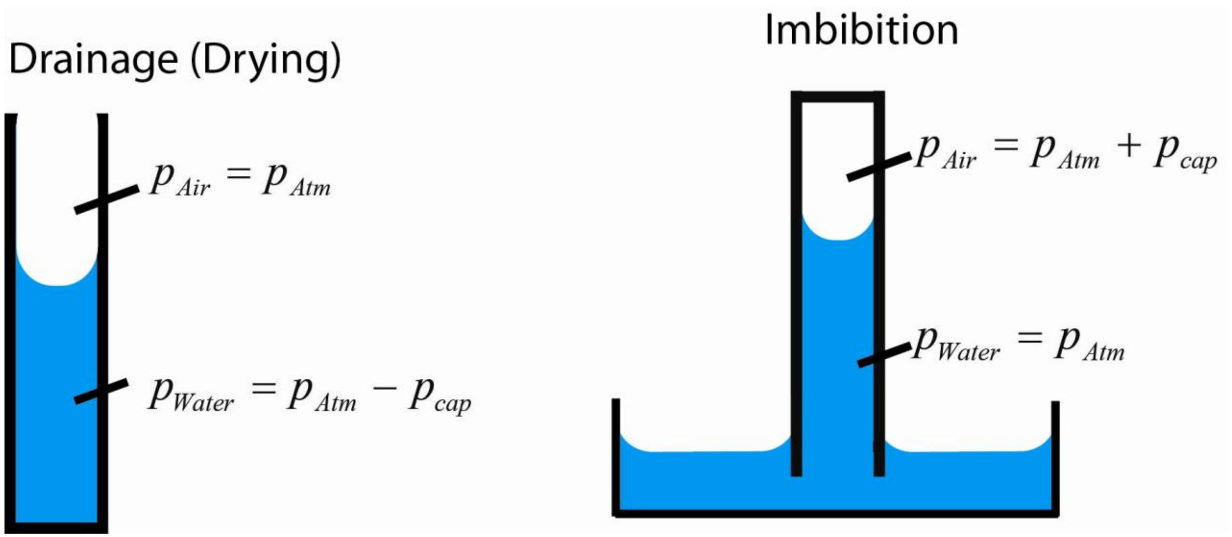
θ = Fluid/Solid contact angle

E = Young's modulus;

ν = Poisson's ratio;

$2a$ = Length of preexisting micro-fracture

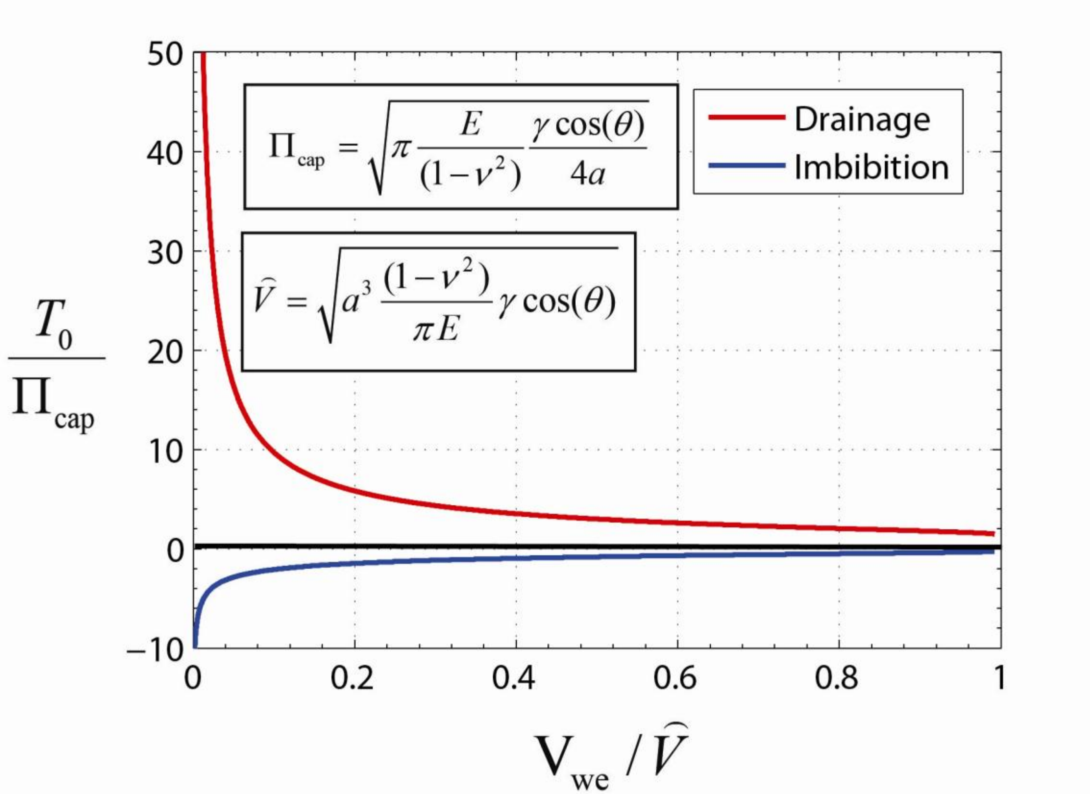
Pressure in each fluid phase during drainage and imbibition



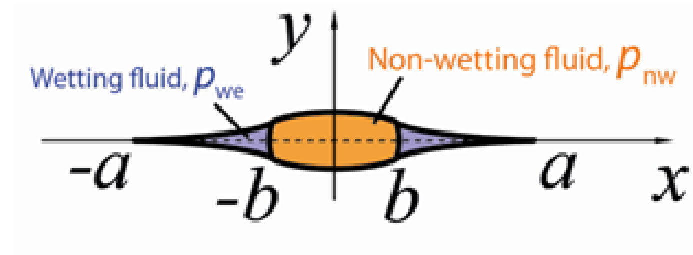
Pressures in wetting (water) and non-wetting (air) phases during drying and imbibition. Gravitational effects on the length of tube are neglected

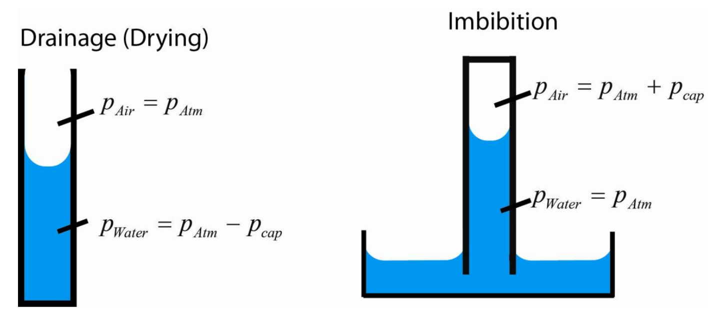
Drainage	**Imbibition**
$p_{we} = p_{nw} - p_{cap}$	$p_{nw} = p_{we} - p_{cap}$
$p_{nw} = Const$	$p_{we} = Const$

Apparent tensile rock strength during drainage and imbibition



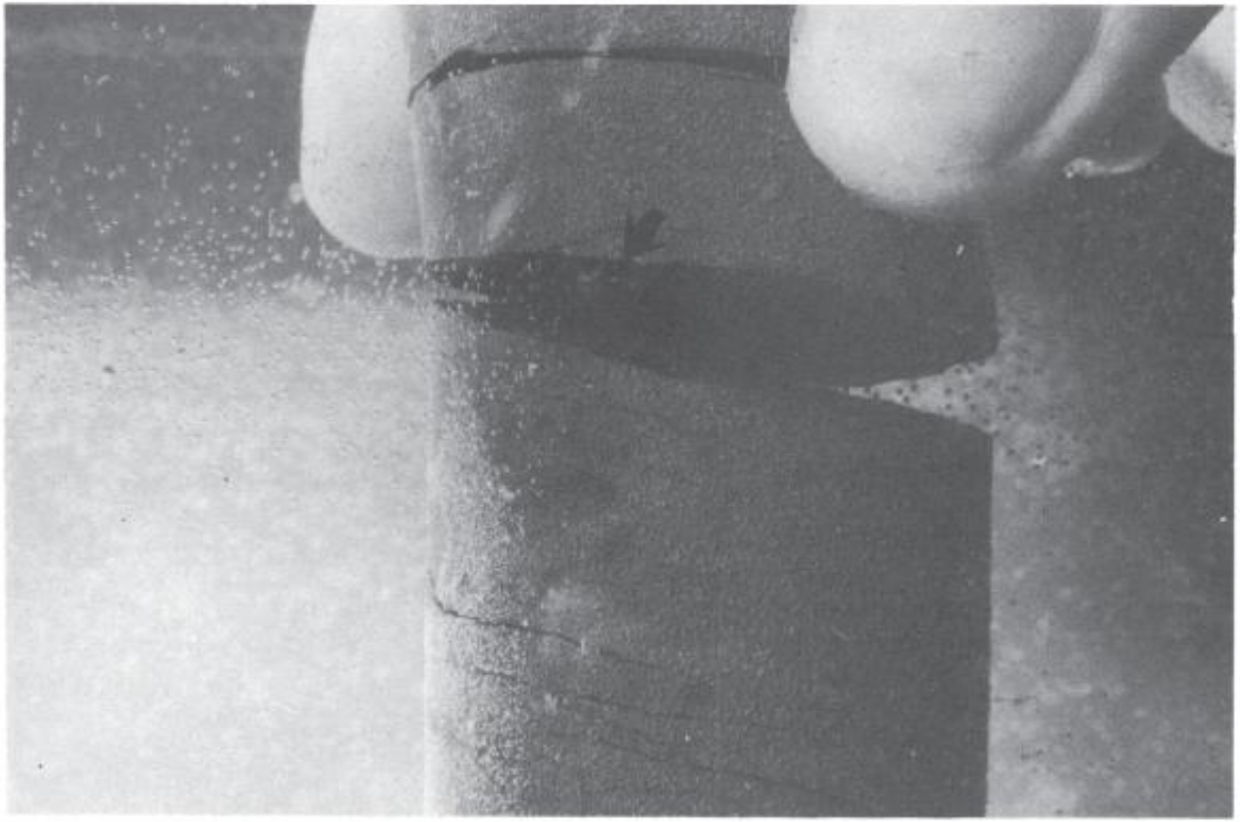
Tensile rock Strength during drainage and imbibition, as a function of volume of wetting fluid inside the crack. (Dimensionless units)





- During drainage the negative pressure on crack tips (p_{atm}-p_{cap}) increase the strength of rock.
- During imbibition high overpressure (p_{atm}+p_{cap}) in center decreases stability of the rock.

Shale sample immersed into water



"Entrapped air bubble in fracture. Its pressurization is responsible for failure",

citation and photo from *SCHMITT et al.*: Shale Testing, 1994.

Conclusions

➢A new theoretical model and analytical solution for capillary pressure and apparent tensile strength during drainage and imbibition conditions is suggested

➢During drainage, the apparent tensile strength of rock is increased, because of negative value of fluid pressure in wetting phase on crack tips, which keeps fracture faces together and increase the stability of the rock.

➢During imbibition the apparent tensile strength is negative, because of formation of high fluid pressure inside trapped non-wetting fluid (*e.g.* air bubbles), which expand fracture faces. Thus during imbibition procedures in the laboratory, the rock sample should be kept in compression, otherwise it may fail in tension.