Special Core Analysis Laboratory Measurements

A special core analysis program typically involves the following experimental measurements:

electrical properties (such as formation factor and resistivity index), wettability, capillary pressure, relative permeability and porosity/permeability measurements at elevated temperatures and pressures. We discuss each measurement technique in detail below.

Special core analysis.

Tests/Studies	Data/Properties
Static tests	
Compressibility studies	Permeability and porosity vs. pressure
Petrographical studies	Mineral identification, diagenesis, clay identification, grain size distribution, pore geometry etc.
Wettability	Contact angle and wettability index
Capillarity	Capillary pressure vs. saturation
Acoustic tests	
Electric tests	
Dynamic tests	
Flow studies	Relative permeability and end point saturations
EOR-Flow tests	Injectivity and residual saturation

Electrical Properties

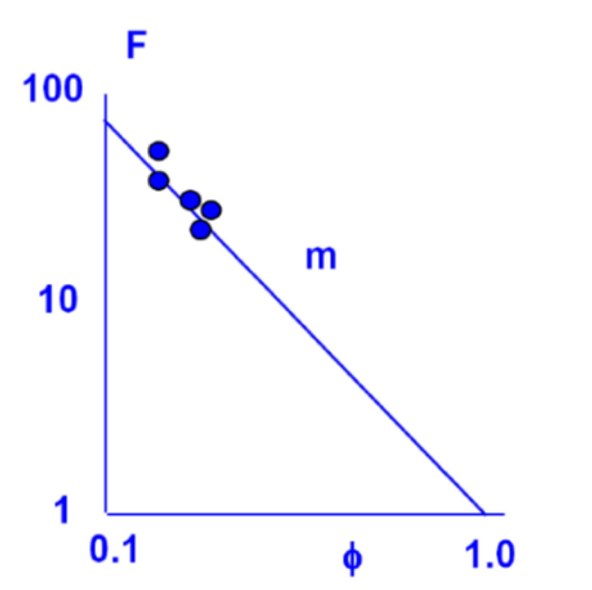
Core materials, with the exception of certain clay minerals, are nonconductors. There fore, electrical properties are mainly determined by the fluids, which fill the pore space of the rock.

Petroleum reservoirs typically contain oil, water and gas; oil and gas being the nonconductor sand water being the conductor. Water residing in porous reservoir rocks contains dissolved salts which allow conduction of electrical currents. The resistivity of a material is the reciprocal of conductivity.

Archie showed that the resistivity of the rock, which is saturated with brine, increases linearly with the resistivity of brine. He defined the proportionality constant as formation factor which can be estimated as:

where F is the formation factor, Ro is the resistivity of brine saturated rock, Rw is the brine resistivity, i is the porosity and m is the cementation exponent which is obtained using a bilogarithmic

plot of formation factor vs. porosity.



Archie derived the abovementioned relationship between formation factor and porosity using the sandstone cores from Gulf Coast reservoirs. The value obtained for the cementation exponent

was around 2. A more generalized form of the Archie equation can be used where formation

factor is a function of internal geometry of the rock as well as the porosity. It can be shown as

below:

$$F = \frac{a}{\emptyset^{m}}$$

where a is a function of tortuosity of the rock and lies between 0.62 and 3.7

If the core is partially saturated with brine and hydrocarbon, the resistivity of the rock increases as brine is the only electrical conductor. Using the experimental data reported in the literature,Archie proposed the following relationship:

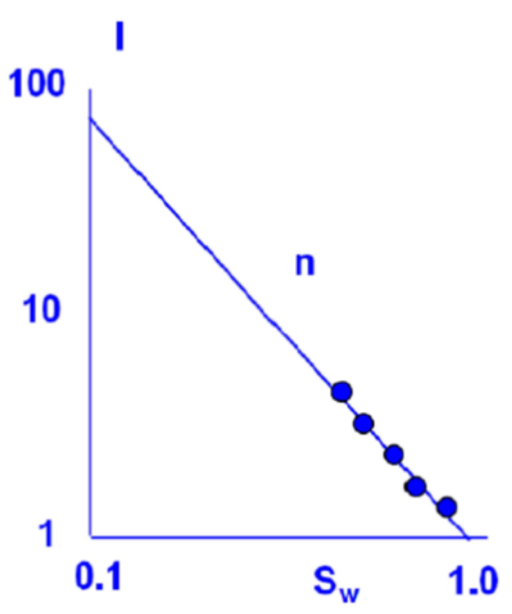
$$I = \frac{R_t}{R_o} = \frac{R_t}{FR_w} = \frac{1}{S_w^{-n}}$$

where I is the resistivity index, Rt is the resistivity of rock which is partially saturated with brine,

Ro is the resistivity of rock which is fully saturated with brine, F is the formation factor, Rw is the

brine resistivity, Sw is the water saturation and n is the saturation exponent which can be obtained

using a bi-logarithmic plot of resistivity index vs. water saturation



Wettability

Petroleum reservoirs consist of water, oil and gas. Dealing with multiphase systems, it is

necessary to take wetting characteristic of different fluids into account. Wettability, sometimes

called energy of adhesion, is defined as the ability of a fluid to spread on a solid surface in the

presence of other immiscible fluids [17].

For an oil-brine system, wettability is the preference of the rock for either oil or water. Basic

core analysis experiments or the experiments considering only the behaviour in primary drainage

(non-wetting phase injection) can be conducted on cleaned core samples. However, when

considering the behaviour on the imbibition cycle (wetting phase saturation increasing),

wettability becomes a determining factor of flow behaviour. Wettability controls the location, flow behaviour and distribution of the fluids in oil reservoirs. The wettability of a core will affect

almost all types of special core analyses, including capillary pressure, relative permeability and

electrical properties as well as the waterflood behaviour and tertiary recovery. The most accurate

results are obtained when experiments are performed with native-state or wettability-restored

cores and representative crude oil and brine at reservoir temperature and pressure. Such

conditions provide cores that mimic wettability as found in the reservoir [18].

Wettability is often quantified by the contact angle, . When two fluids are in contact with a

solid, the angle between the solid and the interface of two fluids is called contact angle, .

Contact angle, by convention, is measured through the denser phase. If it is less than 90º, the

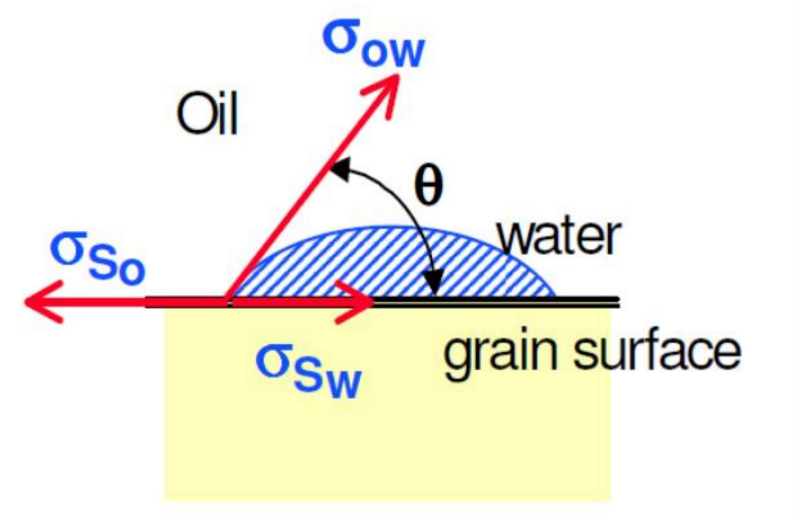
system is considered to be wetting to the denser phase. Otherwise, if the contact angle is

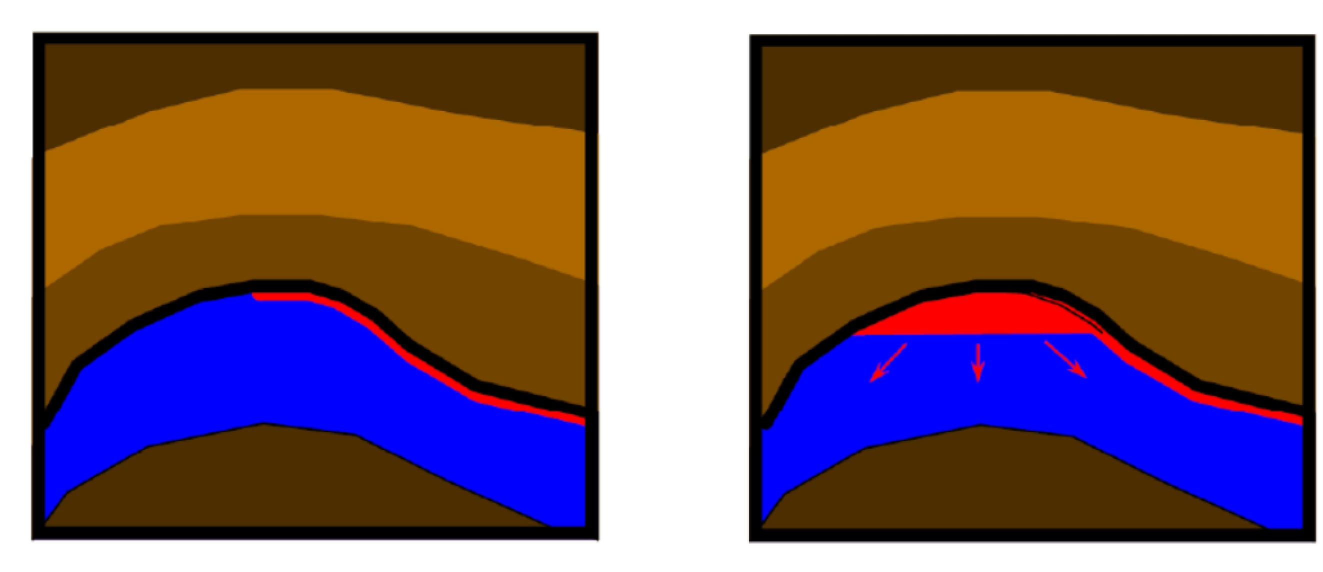
greater than 90º, it is non-wetting to the denser phase. Figure 23 illustrates a water-wet system,

where the contact angle, which is measured through water as being the denser phase, is less than

90º.

An illustration of a water-wet rock surface.
Note that the contact angle is less than 90º in this case.





The reservoir is initially strongly water-wet (left). However, once oil migrates into the reservoir, oil displaces water, ageing takes place and the reservoir becomes more oil-wet or mixed-wet (right).

In dealing with multiphase systems, effects of the forces acting at the interface of the immiscible fluids should be considered. In an oil-brine system, the force acting at the oil and brine interface is called water-oil interfacial tension σ_{ow}, and can be related to the contact angle (θ) as:

$$\sigma_{ow} = \frac{\sigma_{so} - \sigma_{sw}}{\cos\theta}$$

Capillary Pressure:

Capillarity has two important effects in petroleum reservoirs. It is responsible for the initial distribution of the fluids in a reservoir under capillary-gravitational force balance and it is the control mechanism whereby oil and gas move through reservoir pore spaces until they are confronted with a barrier.

Capillary pressure, Pc, is defined as the differential pressure between two immiscible fluids. In an oil-brine system, capillary pressure is generally defined as the pressure difference between the oil phase and the water phase.

where Po is the pressure of the oil phase and Pw is the pressure of the water phase. Note that the pressure difference, Pc, is generally expressed as a function of water saturation, Sw.

Capillary pressure depends on both rock and fluid properties. Interfacial tension, wettability and
pore size distribution are the key parameters to determine capillary pressure. Capillary pressure
between two immiscible fluids in a circular cross-sectional pore element is represented by the Young-Laplace equation as:

$$P_c = \frac{2\sigma\cos\theta}{r}$$

It is worthwhile to mention that capillary pressure is strongly dependent on the saturation history of the system. From a reservoir engineering perspective, both drainage and imbibition capillary pressure curves may be required for integrated reservoir studies, depending on the history of saturation change in the reservoir. From a petrophysicist perspective, Pc is an important parameter which can be used to evaluate field-wide variation of water saturation with respect to the height of the reservoir.

There are two main types of coring

coring axial to the well bore which is called bottom hole continuous coring

coring from sidewall of the borehole which is called sidewall coring

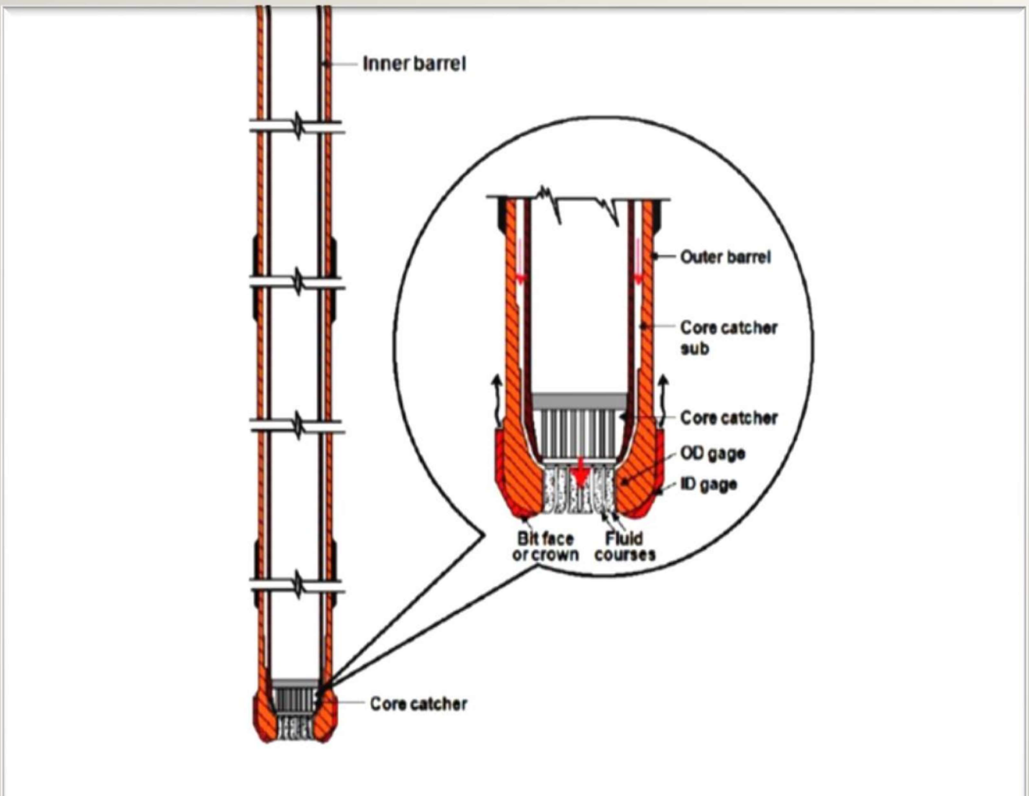


Figure 3. A schematic shows the core barrel and the bit attached to the bottom of the drill pipe

Standard coring techniques

-Sponge coring

-Gel coring

Sponge coring

was developed to improve the accuracy of core-based oil saturation. The core fluids contained in the retrieved core are expelled as a result of depressurization as the core is brought to the surface but are collected and trapped in an absorbent polyurethane material (sponge) lining the inner barrel. The sponge is composed of an open-celled foam with a porosity of 70-80% and a very high interconnectivity between the cells (see Fig 4). The sponge can absorb and collect a volume of fluid up to one magnitude larger than the fluid capacity of most rock materials. Depending on the core analysis objectives, the sponge can be made preferentially oil- or water-wet. An oil-retentive sponge is used with water-based mud. A water-retentive sponge is used with oil-based mud

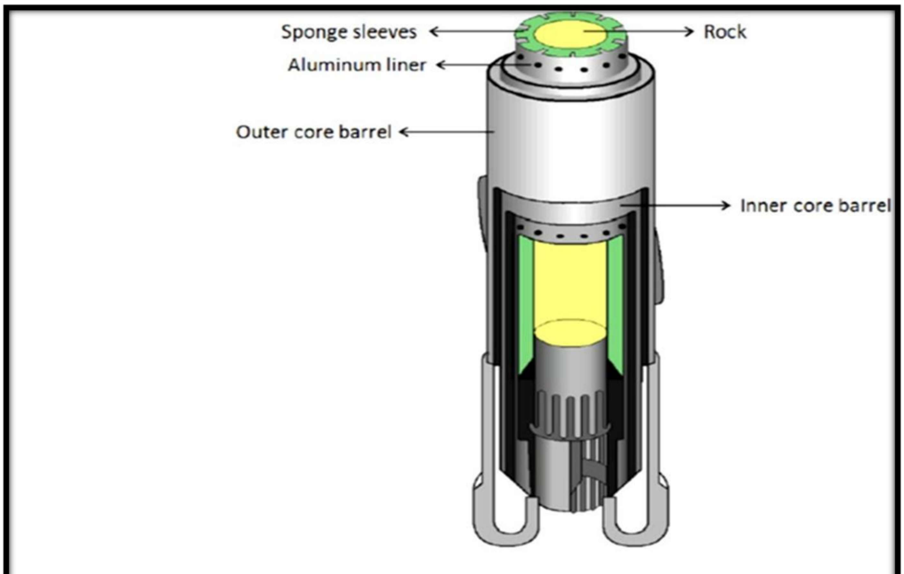


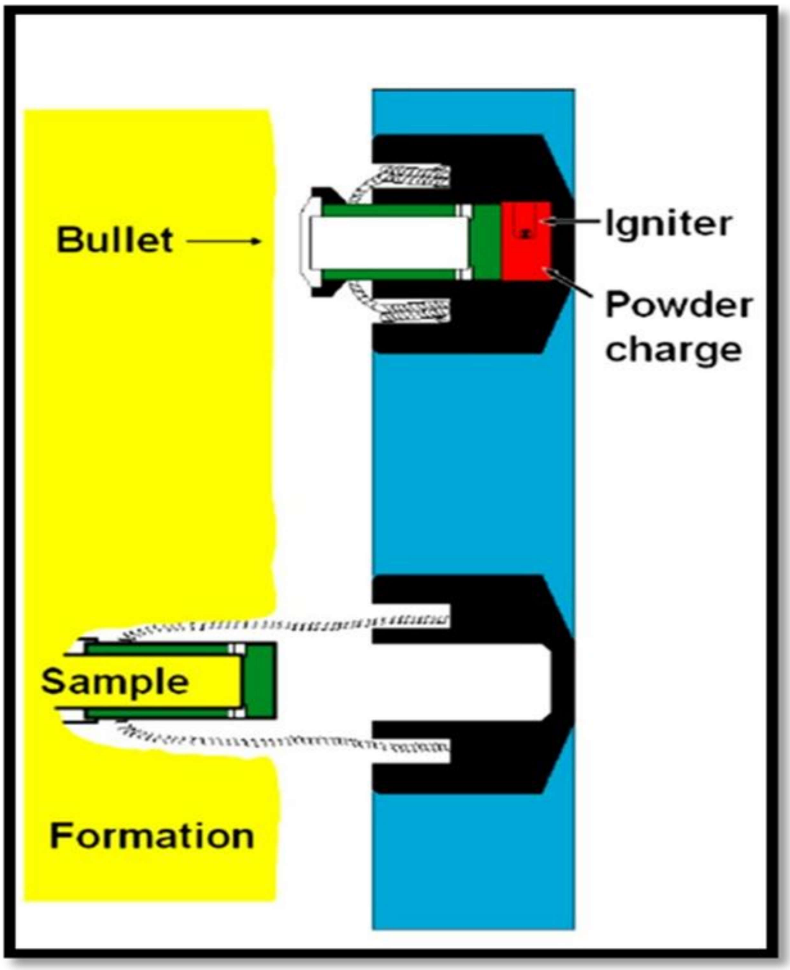
Figure 4. A schematic shows sponge core barrel (Courtesy of Security DBS).

Gel coring

uses high viscosity gel for down hole core encapsulation and preservation, which is an alternative to operator-intensive well site core preservation. Core gel is a viscous, high molecular weight, polypropylene glycol with zero spurt loss, which is non-soluble in water and environmentally safe. Because the gel comes in direct contact with the core during and immediately after it is cut, further exposure to core contaminants is minimized. The high viscosity gel stabilizes poorly consolidated rocks with moderate compressive strengths and enhances core integrity. Core gels can be customized to address a wide range of coring situations and rock types.

Sidewall Coring

Sidewall sampling is another means of obtaining reservoir rock samples if borehole conditions do not allow full-diameter continuous coring. It is also cheaper than continuous axial coring. Rock samples are obtained either by firing hollow cylindrical bullets into the borehole wall, which is called percussion sidewall coring ,or by drilling a small horizontal core in the same way as plugs are cut from full-diameter core, which is called rotary sidewall coring. (Fig 5) shows the schematics of a sidewall sample gun, which is used to obtain percussion sidewall cores, and a rotary sidewall coring tool.



The advantages

of this technique to obtain sidewall core material is quick and relatively inexpensive, the exact depth of coring is known and recovered samples are much larger than drill cuttings, which enable better evaluation of geological variations and quantitative petro physical analysis.

Disadvantages

Disadvantages of sidewall coring are: *

samples (especially percussion cores) are often damaged hence * they may be unsuitable for laboratory tests. Moreover, sample volumes are usually insufficient for performing advanced studies such as multi-phase flow and relative permeability measurements