8.2 Permeabilitätsbestimmungen

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Thema:
Permeabilitätsbestimmung aus Bohrlochmessungen.

Ziel:
Die Bestimmung der Permeabilität von Gesteinen mit Hilfe von Bohrlochmessungen ist ein Weg, um in situ Permeabilitätswerte zu erhalten. Alle bestehenden Meßmöglichkeiten und -Systeme werden besprochen.

Zusammenfassung:
Die ersten Versuche, aus Bohrlochmessungen Permeabilitätsbestimmungen durchzuführen, wurden von TIXIER 1949, WYLLIE und ROSE 1950, unternommen. Sie verwendeten Widerstandsmessungen und Informationen über Porosität.

Die Neuentwicklungen von Bohrlochmeßsystemen erlauben heute Permeabilitätsbestimmungen aus Leitfähigkeits-, Gammastrahlenspektrometer-, Akustik- und nuklearmagnetische Resonanzmessungen. Besonders die akustischen Messungen - Kompressionswellen- und Stoneley-Wellenanalysen sind vielversprechend.

Die Messungen können jedoch Permeabilität nicht direkt messen, sondern nur einen "Index" bringen. Nur durch den Einsatz des Repeat Formation Tester kann Permeabilität direkt bestimmt werden.

Hinweis:
Die im englischen Text verwendeten Abbildungshinweise beziehen sich nur auf diesen Report 88-4.

Estimation of Permeability from Wireline Logs

Introduction

Since the introduction of geophysical measurements in a borehole in 1927 the challenge for the logging industry has been to measure permeability as a continuous log downhole. We are able to evaluate porosity, watersaturation and lithology from different logs. Though, - to log permeability - industry has so far not succeeded.
The first indication came with the discovery of the Self Potential (SP)-phenomena. Mistakingly considered as a porosity measurement, it became later - under certain conditions - an indicator for permeability.
A great number of other measurements, electric, radioactive, acoustic, magnetic and dynamic have been developed. About the same numbers of evaluating methods have been designed - but the result is the same, we are able to estimate a "permeability index" - not more.
The reason for this is rather simple. For direct permeability measurements moving fluids through rock are required. Downhole, with mud cake sealing the only accessible surface of the borehole wall and the hydrostatic head of the mud collum keeping the pressure balance, measurable fluid motion is prevented.

The only wireline tool available is the Repeat Formation Tester, which could be used to make stationary measurements of permeability, by opening the formation to atmospheric pressure and forcing fluid movement over short periods of time from the formation into the tool.

Before describing individual logging systems it will be necessary to define permeability and its affecting factors. The French engineer Henry Darcy published 1856 his studies for quantitative fluid flow calculations.

Establishing flow characteristica for different sandstones he found that he needed a proportionality constant in his calculations which he determined to be permeability.

Today industry has adapted his law - Darcy's law - and uses the "darcy" as standard unit of measure for permeability. It is defined as 1 cm^3 of fluid with viscosity of 1 centipoise (water) flowing through 1 cm^2 of rock surface in 1 second under a pressure gradient of 1 atmosphere per centimeter of length in the direction of flow.

Factors influencing permeability are manifold and vary strongly with rock type, type and amount of porosity, grain size and packing, tortuosity of pore space, clay content and authigenesis, cementation, sorting, irreducible (bound) water saturation, anisotropy. Fluid type and flow regime must be considered (Abb. 8.5).

Therefore, to fully understand the permeability of any rock the knowledge of these factors is essential.

Therefore, it should not be too surprising that we can only state: we are unable to measure in-situ permeability directly - but we are working towards defining a "best possible approximation".

Wireline Tools used for Permeability Estimation are:
Resistivity/Conductivity: Induction Log, Dual Laterolog
Porosity/Saturation: Sonic, Density, Neutron, Induction, Dual Laterolog
Acoustic: Sonic Log - Compressional and Stoneley (Tube) Waves
Nuclear Magnetic Resonance: Nuclear Magnetic Resonance Log/Natural Gamma Ray Spectrometer
Dynamic Flow Measurement: Repeat Formation Tester, Production Logs (Abb. 8.6).

Resistivity/Conductivity Measurements

- Resistivity Gradient and Porosity versus Saturation

In 1949 Tixier M.P. proposed to use the difference in densities of hydrocarbons and water and plot it against a resistivity gradient - or resistivity change - observed on the logs opposite the transition zone.

The resistivity gradient "a" is formed by dividing the change in resistivity over the transition zone "ΔR" by the length over which this change is observed "ΔD" and by the resistivity in the waterbearing interval "Ro".

The gradient is:

$$a = \left(\frac{\Delta R}{\Delta D} \cdot \frac{1}{R_o} \right)$$

INTRODUCTION

Challenge

Measure in-situ absolute permeability

Requirement

Moving fluids through rock

Environment Downhole

Mud cake sealing surface of borehole wall
Hydrostatic head keeping pressure balance
Measurable fluid motion prevented

Factors Influencing Permeability

- rock type
- type and amount of porosity
- grain size, sorting, packing and cementation
- tortuosity of pore space
- clay content and authigenesis
- irreducible water saturation
- fluid type, flow regime

etc. etc.

Permeability from Wireline Logs | KTB

Abb. 8.5

INTRODUCTION

Systems Available Today

- Resistivity/Conductivity/Porosity/Water Saturation
    - Resistivity Gradient versus Density Difference
    - Porosity versus irreducible Water Saturation
    - Specific Surface Area Measurements
- Acoustic Measurements
    - Compressional wave
    - Stoneley (Tube) wave
- Nuclear Measurements
    - Nuclear Magnetic Resonance (NMR)
    - Natural Gamma Ray Spectrometer (NGT)
- Dynamic Measurements
    - Repeat Formation Tester
    - Production Logs

Result

"PERMEABILITY INDEX" from logs

POINT INFORMATION FROM RFT

Permeability from Wireline Logs

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Abb. 8.6

Plotting this gradient against the density difference on double logarithmic scale, permeabilities follow straight lines (Abb. 8.7).
Knowing all the deficiencies of this method it still could be applied if conditions are favourable.

- Porosity versus irreducible Water Saturation

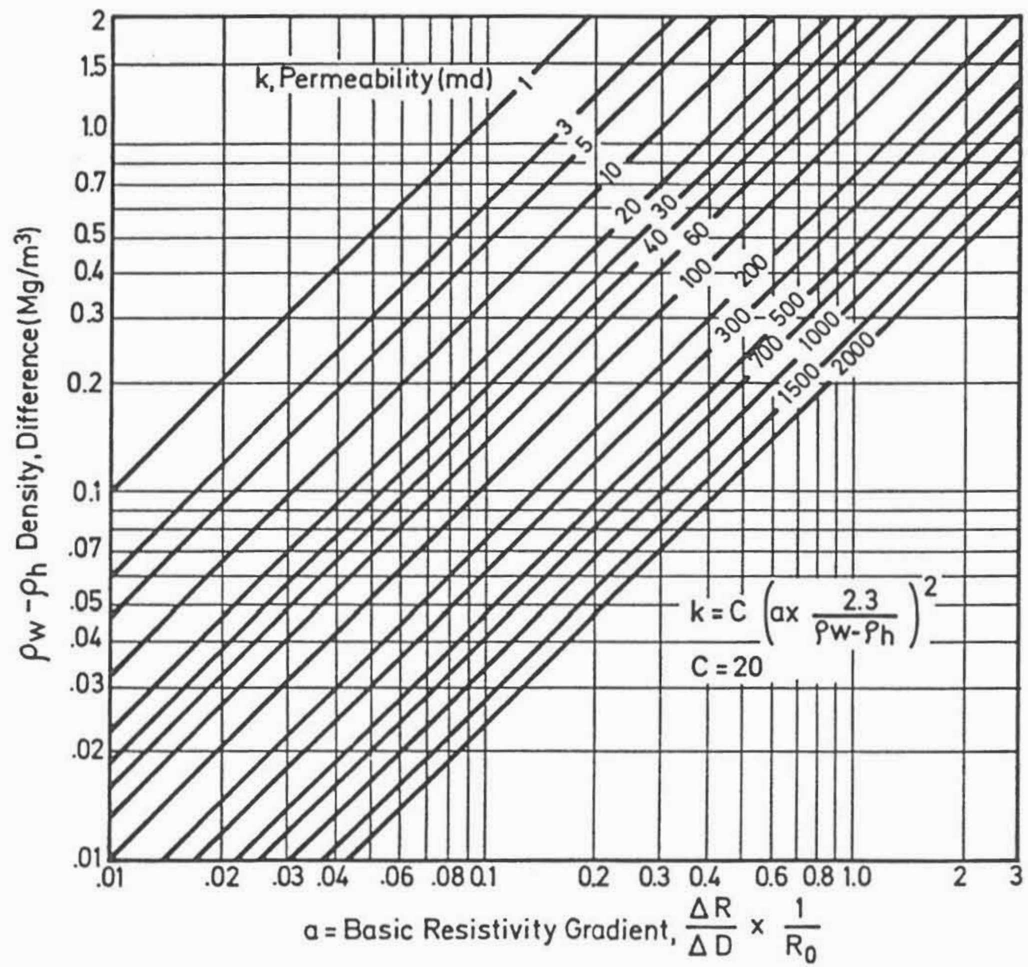
Wyllie and Rose established 1950 the empirical relationship for permeability

$$K = C \cdot \phi^3 / (Sw)^2_{irr}$$

where C is a constant, ø is porosity and Sw_{irr} is the irreducible water saturation (C = 250 for medium density oil; C = 79 for dry gas).
For this formula charts have been prepared giving ø in the X- and Sw_{irr} in the Y-axis on linear scale. It should be used for intervals above the transition zone (Abb. 8.8).
Porosity is estimated using either Sonic, Density and/or Neutron logs directly or the value is taken from either Quick-look or computer evaluation. With the help of resistivity/conductivity logs the irreducible water saturation is calculated.
Plotting these two parameters the intersection defines the intrinsic (absolute) permeability of the rock. If different types of hydrocarbons are present a correction factor has to be applied. It takes into account the difference in densities of the fluids ($\rho_w - \rho_h$) and the distance (h) above the water table.
Here again, - under favourable conditions this empirical relationship is still valid.

- Specific Surface Measurements

A more sophisticated approach has been taken by Pape et al. 1981 and 1984. Permeability has been calculated from specific surface measurements and the formation factor.



Permeability from Resistivity Gradient

[SCHLUMBERGER]

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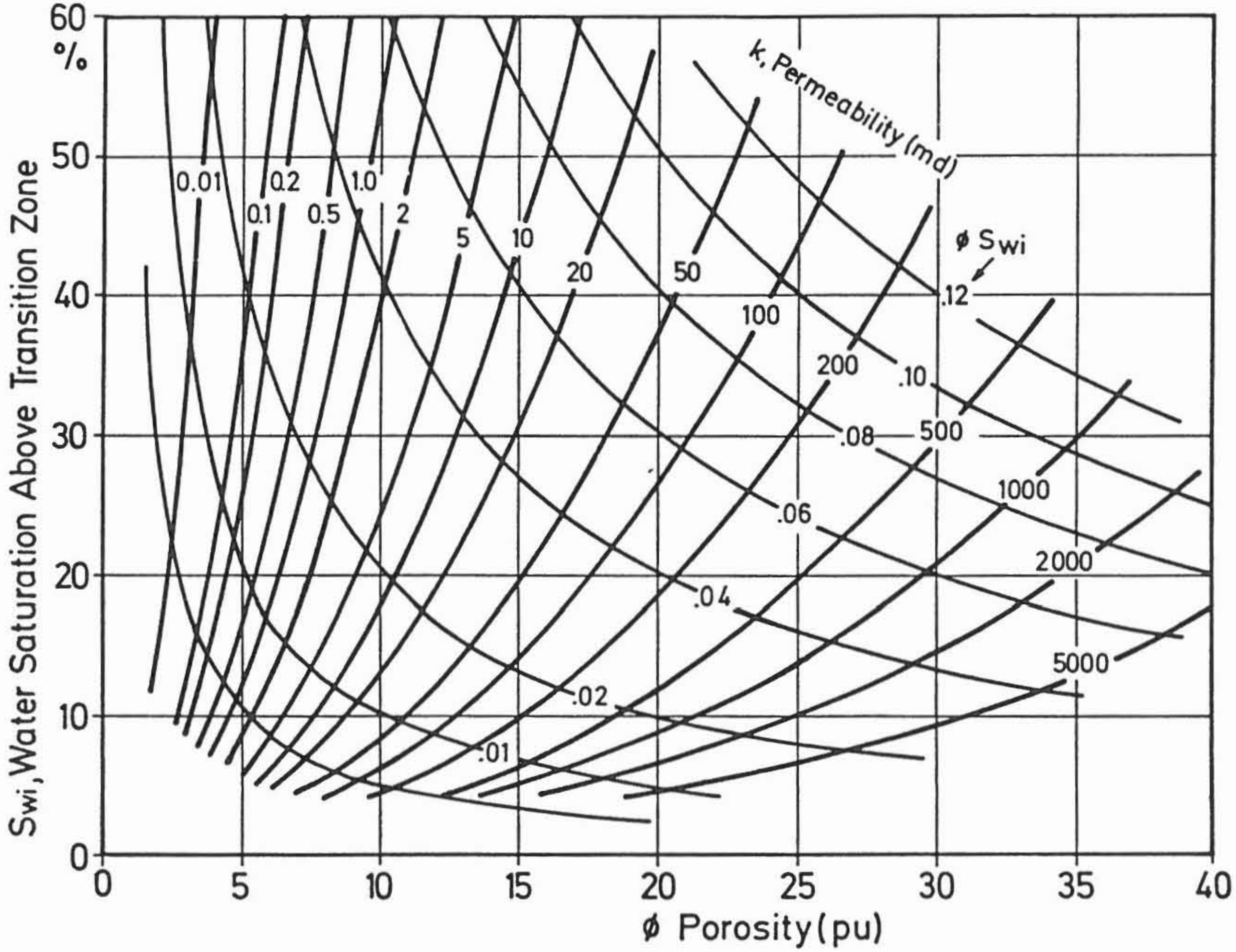
Abb. 8.7



Permeability from Porosity and Water Saturation

[SCHLUMBERGER]

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Abb. 8.8

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The theoretical studies and measurements made in the lab for evaluating the specific surface area led to an improved KOZENY-CARMAN permeability relationship:

$$K = \frac{\phi}{T} \cdot \frac{Q^2}{2\,S_{por}^2}$$

T = tortuosity
Q = conversion factor
S_{por} = specific surface area given by nitrogen adsorption measurements.

Setting hydraulic tortuosity (T) equal to electrical tortuosity (X) will bring the formation factor into the equation. Solving for permeability K and introducing numerical values for Q the following formula is reached:

$$\log K = -\log F - 3.1085 \log S_{por} + 2.6770$$

This is the so-called "first Paris-Equation".
F = Formation Factor

Replacing the term for specific surface area in this equation by interface conductivity, calculated from rock conductivities measured at different salinities, the "Second Paris Equation" is obtained:

$$K = 0.5767 \cdot 10^{-4} \cdot q_o^{(\pm)} \cdot Cq_o^{-3} \cdot F^{-4}$$

$q_o^{(\pm)}$ = lamellar-smoothing factor
Cq_o = interlayer conductivity

S_{por} and $q_o^{(\pm)}$ are obtained from lab measurements
C_{qo} and F can be evaluated from logs.

Rock conductivity and formation factor are both depending on resistivity/conductivity measurements.

Acoustic Measurements

The introduction of continuous acoustic measurements in a borehole in the late fifties opened the way to differentiate lithologies and estimate porosity.

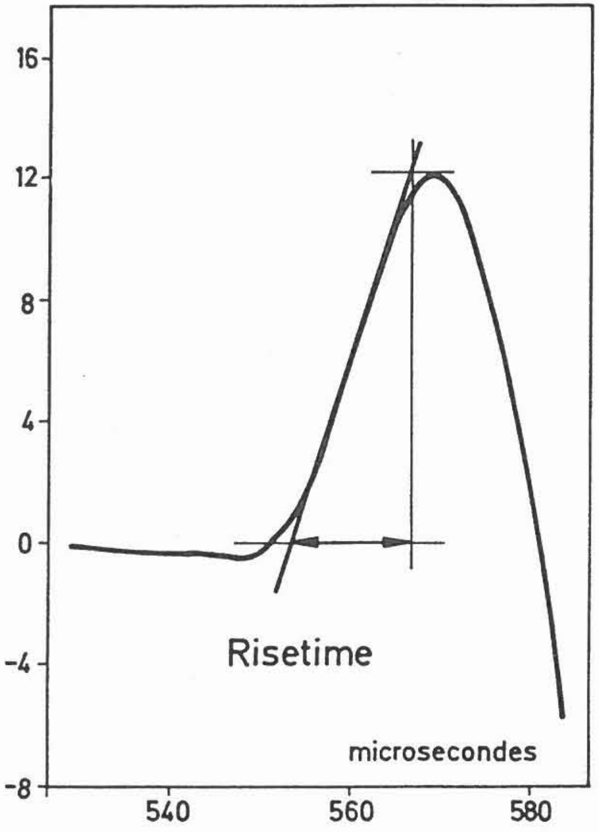
In more recent times, after computer technology has made it possible to record not only transit time but also the complete wave train of the reflected acoustic signal, the study of the information contained in the wave form has taken momentum.
The first step has been to separate compressional and shear waves and compute compressional and shear transit times (DTC and DTS) for the estimation of rock mechanical properties.
Then attempts have been made to relate acoustic signals to permeability. In fact several possible ways have been found to compute a permeability index from Sonic Logs.
Lebreton et al. suggest to work with the compressional (P) portion of the wave train, while Staal et al., Hsui et al., Mobil Oil and Schlumberger prefer the portion of the Stoneley (Tube) wave.
All acoustic measurement attempts follow the same model concept, i. e. Biot's Theory of wave propagation. The model is based on a medium consisting of an elastic solid matrix and a viscous pore fluid. The relative motion between the pore fluid and the matrix created by acoustic energy results in energy dissipation.

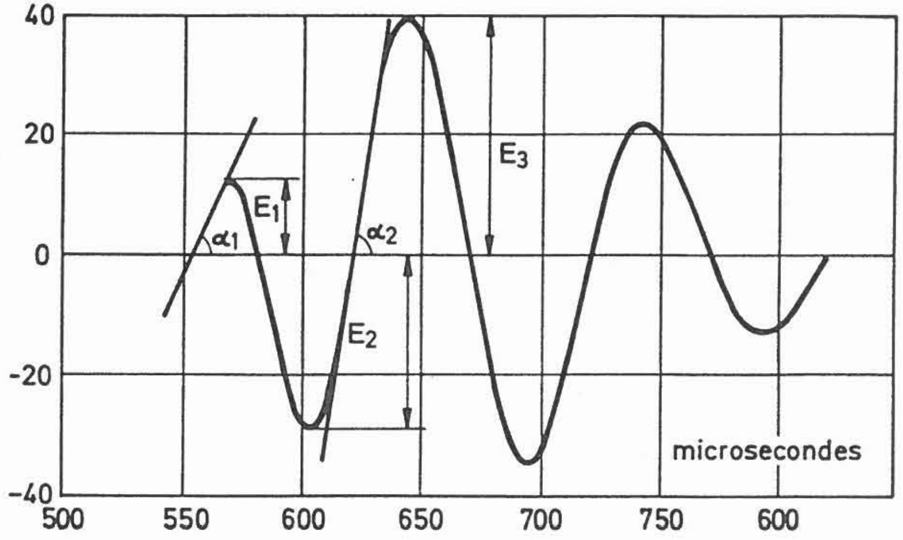
- The Lebreton approach

The recorded sonic wave form is analysed over the first three cycles. Either the absolute peaks of the first three half-cycles E_1, E_2, and E_3 are taken or the slopes at the point of inflection of the rising part of the first two maxima G_1 and G_2 (Abb. 8.9).
The index being the ratio of

$$I = \frac{E_2 + E_3}{E_1} \text{ or } \frac{G_2}{G_1}$$

LEBRETON APPROACH: Compressional portion of acoustic wave train





$$I = \frac{E_2 + E_3}{E_1} \text{ or } \frac{G_2}{G_1} \quad ; \quad \boxed{I = \alpha \log \frac{K_v}{\mu} \cdot \beta}$$

Permeability from Acoustic Measurements

KTB

Abb. 8.9

These parameters are depending on the attenuation of the acoustic signal. The alteration of the attenuation is related to, - one way or another - permeability of the medium.
The relationship established is:

$$I = \alpha \log \frac{K_V}{\mu} \cdot \beta$$

K_V = permeability evaluated along well axis direction
μ = viscosity of rock wetting fluid
α, β = constants attached to tool and well environment

It is recommended to run the Sonic Tool either with 4 or 5 ft spacing eccentered for good signal acquisition.
Examples demonstrating application in geothermal wells in France are striking.

- Stoneley (Tube) wave concept (Abb. 8.10)

Rosenbaum (1974) demonstrated in his studies that a relationship exists between tube wave attenuation and permeability.
The tube wave is a guided wave and is present only when there is a borehole to serve as a waveguide.
This wave is of much lower frequency, higher amplitude and has slower velocity than P- and S-waves. As stated, the attenuation is due to fluid flow from the borehole into the formation initiated by the passing wave.
Tube wave energy dissipation increases with increase in fluid motion - therefore increasing permeability. If the amplitudes of tube waves measured at two receivers a certain distance apart are compared, the attenuation should be an indicator of permeability of the formation between (Abb. 8.11).
Rosenbaum separates two models - the "sealed interface" (complex impedance contrast between borehole fluid and surrounding formation) and "open interface" (communication between borehole fluid and Biot's porous medium).

Using a gated system he found that for the sealed interface maximum sensitivity to permeability was given between shear-wave and direct-wave arrival. For the "open interface" all information after the shear-arrival could be used.
The compressional wave arrival was found the least sensitive.

Stoneley (Tube) Wave

ACOUSTIC FLOW

Across Borehole Interface

FLUID COMMUNICATION

Between Borehole and Formation

ENERGY DISSIPATION

Acoustic Amplitude: Attenuation

MOBILITY RATIO

$$\frac{\text{Permeability}}{\text{Viscosity}}$$

Permeability-
Acoustic Measurement

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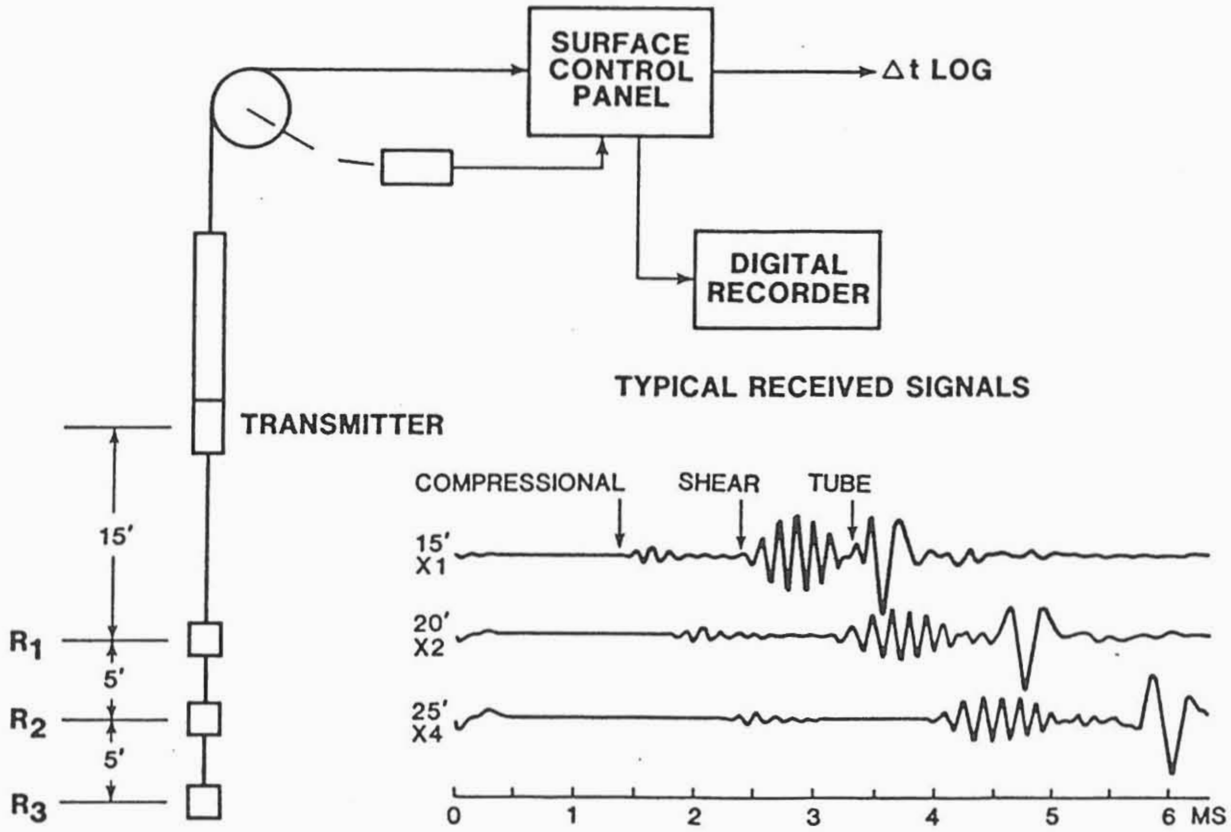
Abb. 8.10

Mobil Oil Long Spacing Acoustic Log (LSAL)



Permeability from Acoustic Measurements

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Abb. 8.11

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Results obtained using this method of comparing energies (the square of the amplitude is proportional to the acoustic energy) measured in a time window (e. g. from 1 400 - 2 800 μsec) after normalisation, are very encouraging and further studies are in progress (Abb. 8.12).

Nuclear Measurements

- Nuclear Magnetic Resonance (NMR)

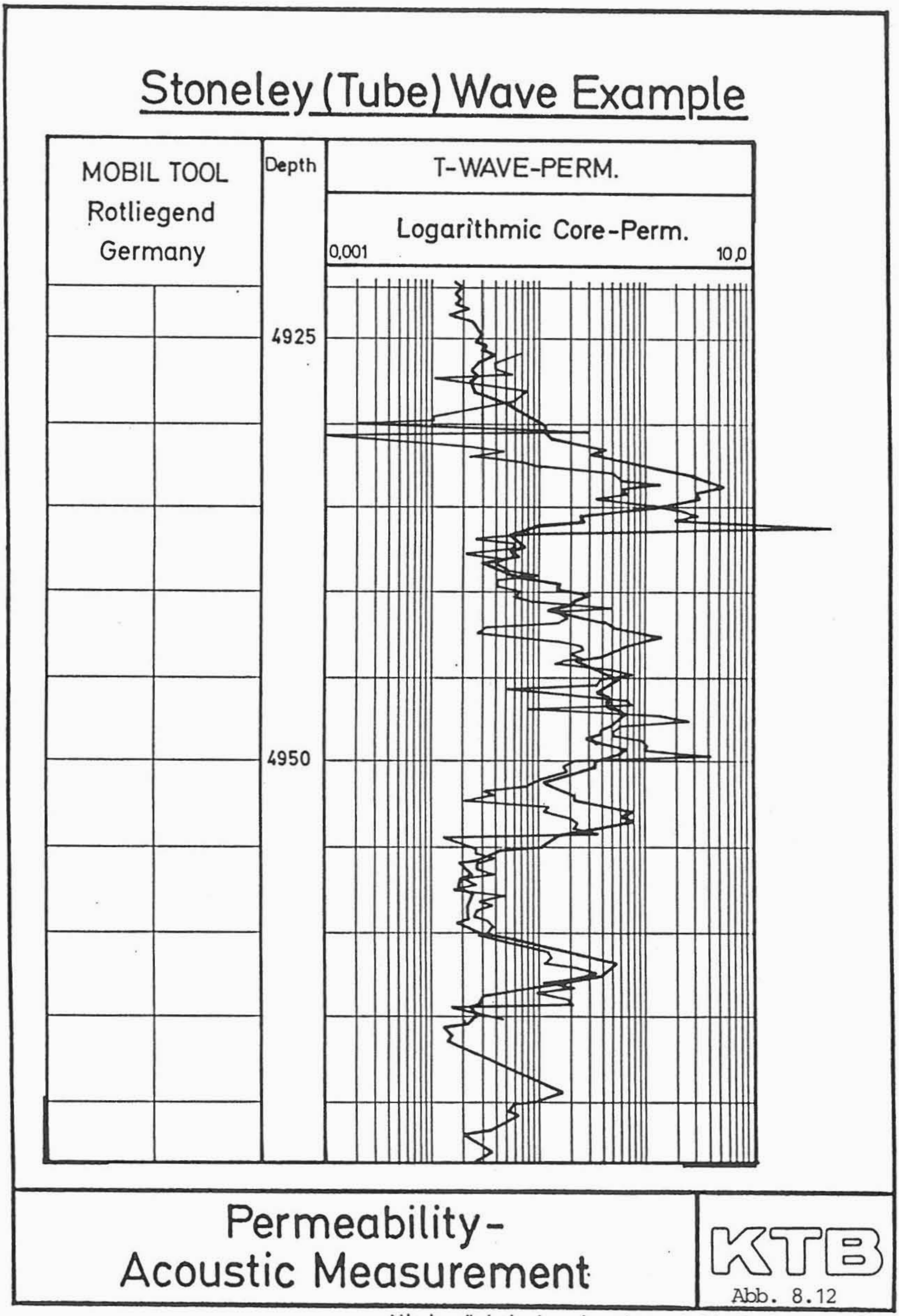
A not so widely used method to estimate in-situ permeabilities is to log with the Pulsed Nuclear Magnetic Resonance Tool (NMR). First, there are not to many tools around and second, the borehole mud needs special preparation. However, the method itself is a very interesting one.

Korringa, Seevers and Torrey ("KST"-1963) have developed a model for studying the properties of fluids in porous media by use of the NMR technique. They discovered that the specific surface area of rock (S), was directly relatable to nuclear magnetic relaxation time.
By establishing a technique for measuring the surface-to-volume ratio distribution in a porous medium through the relaxation of spin polarisation of protons in a hydrogenous fluid, the proposal for determining permeability for sandstones was made.
The KST-model makes 3 basic assumptions:

- there is a thin layer of fluid at the liquid-solid interface which has a relaxation time (T_{1s}) less than the relaxation time of the bulk fluid (T_b).
- between this layer and the bulk fluid is an interactive proton diffusion process which is characterized by a certain time constant (τ_m)
- the pore diameter is less than the diffusion length of the molecules in the fluid.

Applying this theoretical model to real rock is more complex as more than two relaxation components are present, giving therefore

$$K_i = A \cdot \phi_i \cdot \left(\frac{1}{T_{1i}} - \frac{1}{T_b} \right)^{-2}$$



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The factor A includes tortuosity (τ) and the liquid-solid interface parameter ($\frac{h}{\tau_S}$) must be evaluated experimentally.
The estimation of tortuosity is difficult. Schopper (1966) and Riepe et al. (1986) suggested to use the formation factor relationship by equating hydraulic tortuosity (τ) to electrical tortuosity (X).
Permeability estimates from NMR measurements are strongly depending on the variability of factor A due to changes in rock type, grain size, cementation etc. etc. Therefore, this method is inadequate for determining absolute permeabilities.

Looking at the example comparing core derived permeabilities (plugs at one foot intervals) with NMR permeabilities good agreement is obtained only by proper choice of the value for A (Abb. 8.13).
It must be recognized that "A" is the "calibration" for permeability estimates using NMR-measurement.

- Natural Gamma Spectrometer (NGT)

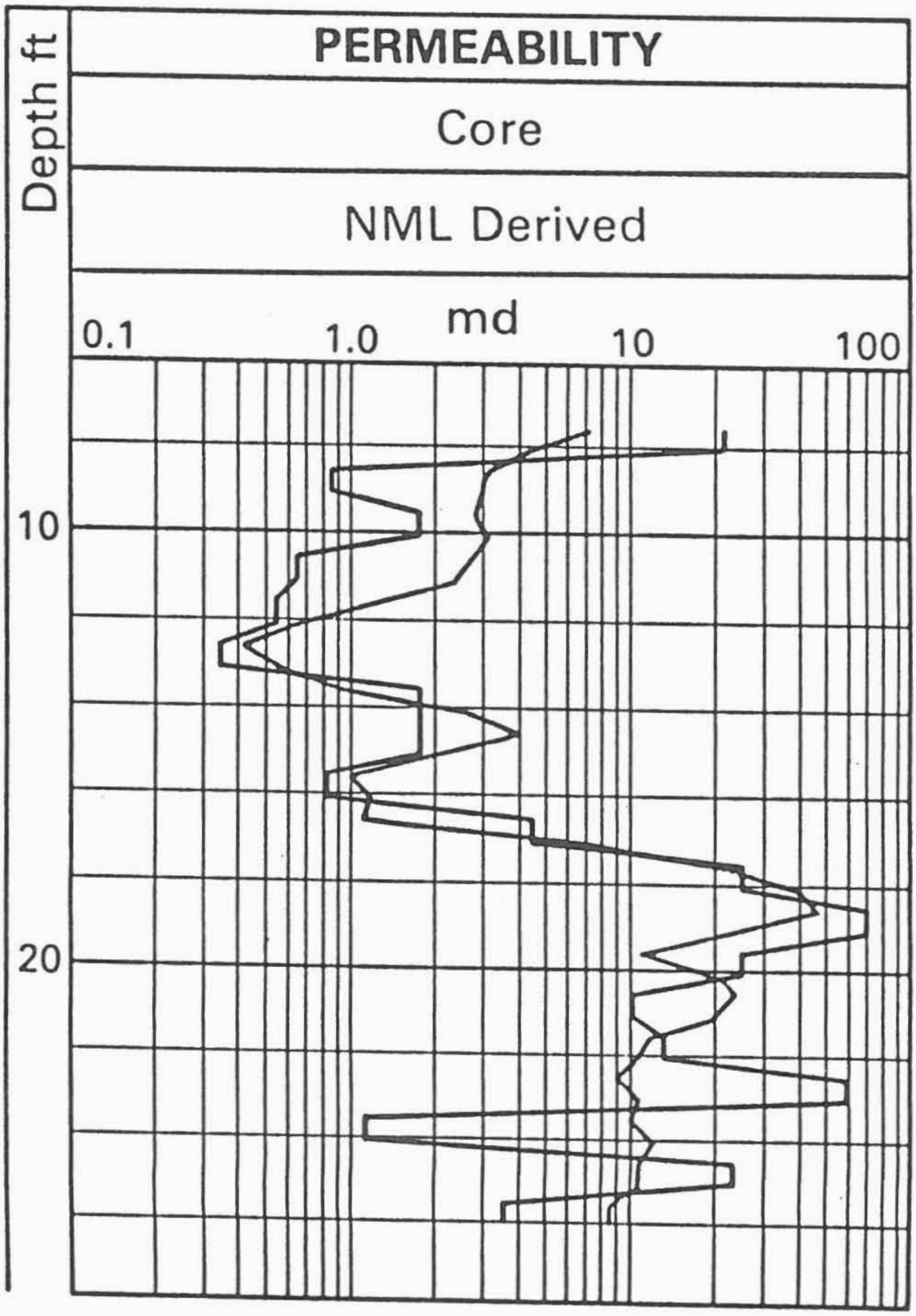
It has been observed that in rocks the insoluble Thorium complexes are tightly adsorbed to mineral surfaces. This means, - specific surface area could be estimated by the use of Natural Gamma Spectrometer measurements sensitive to the Thorium spectrum.
An empirical relationship between Thorium content C_{TH} and specific surface area has been proposed by Riepe et al. (1986):

$$C_{TH} = a_{TH} \cdot Sg^{b}$$

a_{TH} = means Thorium adsorption density
Plotting the Thorium levels of different rock types on double logarithmic paper a minimum of 1ppm TH/$(m^2/g)^{1/2}$ and a maximum of 5ppm TH/$(m^2/g)^{1/2}$ has been found. The slope of the border lines represents the empirical exponent b = 0.5 for Sg the specific surface area from NGT.
If heavy minerals are present in the rock resulting in higher Thorium readings, corrective actions are required. These minerals are detected either by increased density values, high photoelectric effect (Pe) or identified by the Spectrometer measurements themselves as most heavy minerals exhibit an increase in Uranium and a decrease of the Potassium reading.

NMR-EXAMPLE

Comparison NMR: Core Permeabilities



Permeability-Nuclear Magnetic Resonance

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Using the specific surface area term

$$S_{por} = \frac{1-\phi}{\phi} \cdot \rho_{ma} \cdot Sg$$

converting it by applying the Thorium concentration when substituting the term in the so-called "first Paris equation" Riepe et al. arrive at their "Aberdeen equation":

$$K = \frac{475 \cdot 3}{F} \cdot \left[\frac{1-\phi}{\phi} \cdot \rho_{ma} \cdot \frac{1}{q_o} \left(C_{TH}/a_{TH} \right)^2 \right]^{-3.1085}$$

All parameters in this equation are obtainable through logs.
q_o = lithology factor, which needs geological and mineralogical information. However, as a first approximation $q_o = 1$ can be used.
Using this form of estimation good correlation of core- and log derived permeabilities have been found in Valanginean sandstones and carbonates of Jurassic age (Kimmeridigian and Cornbresh) in Germany.

Dynamic Flow Measurements

- Repeat Formation Tester

There are two different methods used to derive permeabilities with this tool:

1. Analysis of the pressure drawdown recorded with the pretest systems, and
2. Analysis of the pressure build-up curve.

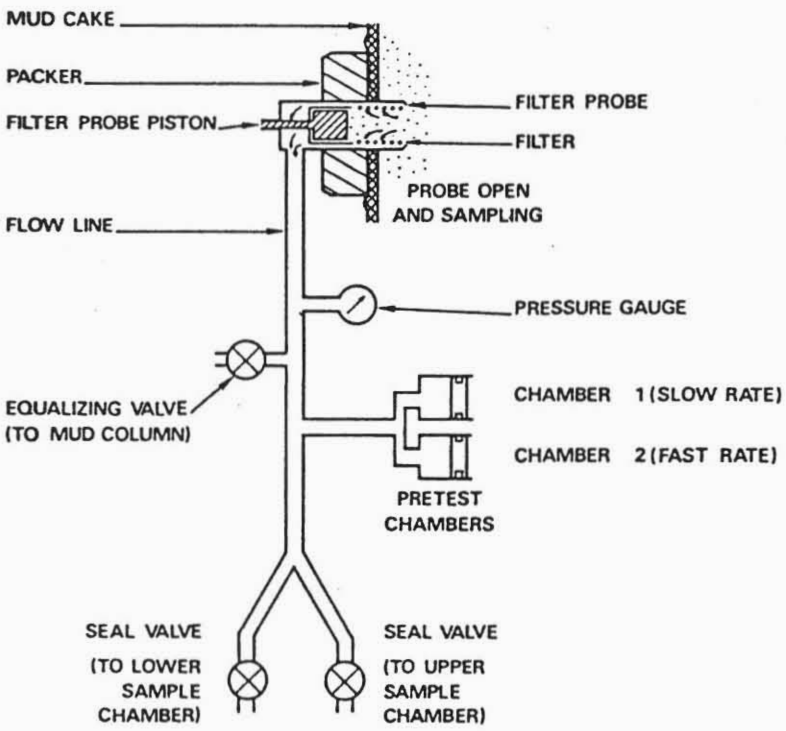
By conception, these values of permeability will always be point information and will in inhomogeneous formation not be representative for a total reservoir. Further, it must be remembered that these estimates are derived from the zone which has been strongly altered by the drilling process and subsequent mud invasion.

Permeability from pressure drawdown

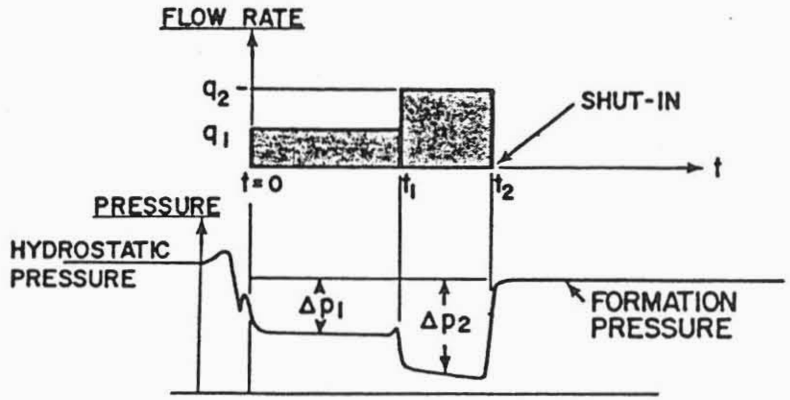
After setting the tool at test depth the pretests are automatically and sequentially activated. Twice 10 cm^3 of fluid are drawn from the formation by retraction of a piston in the filter probe and the pressures in the flow-line are recorded. The system allows for chamber 1 a "low-flow-test" due to slower piston movement than for chamber 2 - the "high-flow-test". The rates of fluid withdrawal are about 50 cm^3/min and 125 cm^3/min. Depending on tool and local conditions the ratio of the flow rates in the two periods is approximately 2.5 (Abb. 8.14).
From the recorded pressures, the well defined volumes of fluid produced over a clearly recorded short length of time an estimate of permeability for both flows can be computed. By averaging the two values a "minimum" effective permeability can be obtained.
This permeability will be representative for the flow of mud filtrate through the formation, as this pretest feature is only able to test the area next to the borehole. The example given shows the typical pressure response record of the pretests. The initial hydrostatic pressure at testing depth increases slightly when the packer is set, this is followed by a drop in pressure due to piston retraction. When the piston stops the pressure increases again until it falls sharply when the pretest begins. When the piston of chamber 1 is completely withdrawn and the first pretest is completed it is automatically followed by the second, - the "fast" pretest. After piston 2 reaches final position the pressure builds up to formation pressure. Assuming a quasi-hemispherical flow the formula for computing permeability from pressure draw-down is (Abb. 8.15; Abb. 8.16):

$$K_d = C \cdot \frac{q \cdot \mu}{2\pi \cdot \Delta p \cdot r_p}$$

q = flow rate (cm^3/sec)
μ = fluid viscosity (cp)
Δp = drawdown from formation pressure
C = flow shape factor
r_p = effective probe radius



RFT pretest and sampling principle



Schematic of RFT analog-pressure recording

RFT Pressure Recording

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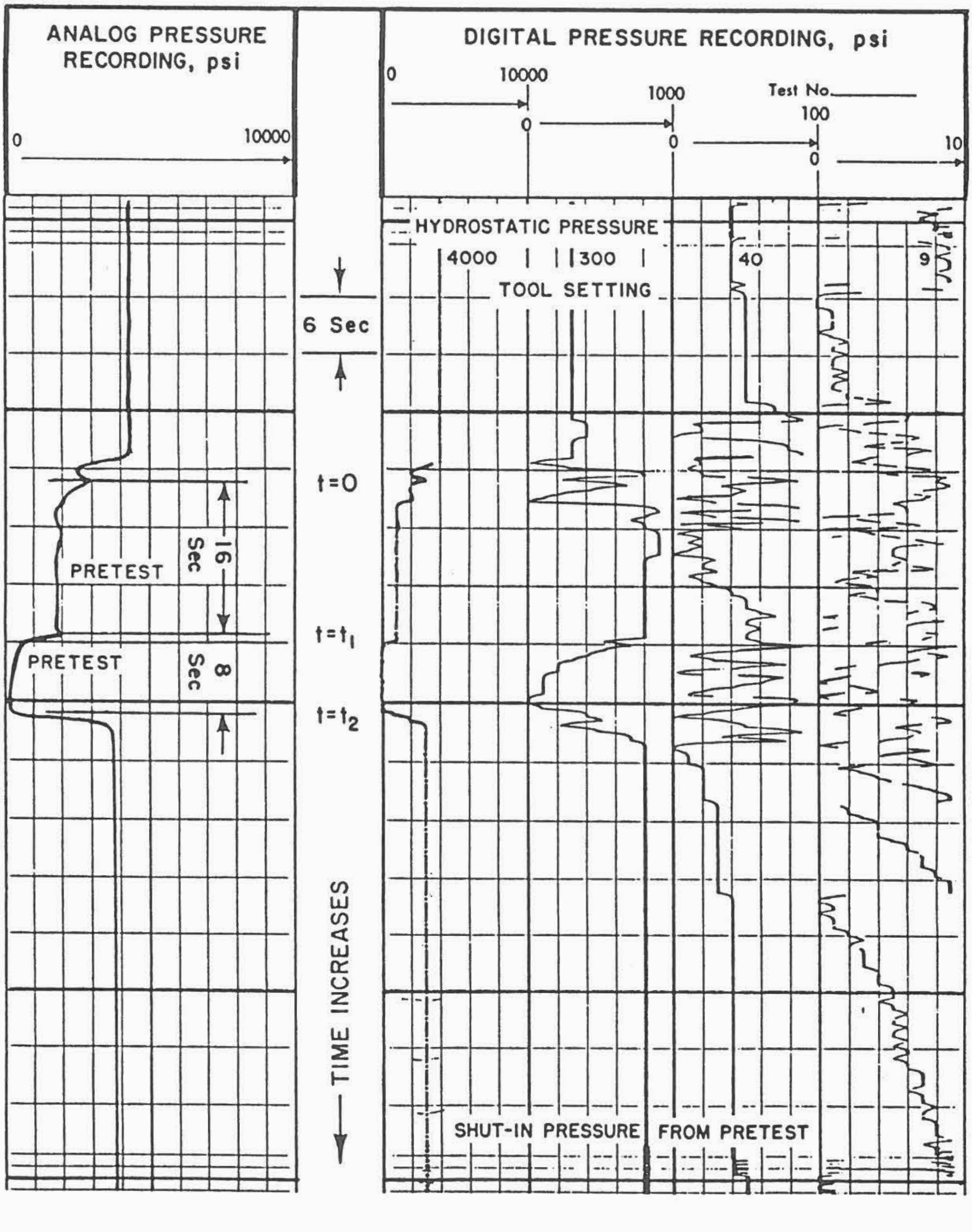
Abb. 8.14



RFT Pressure record Example

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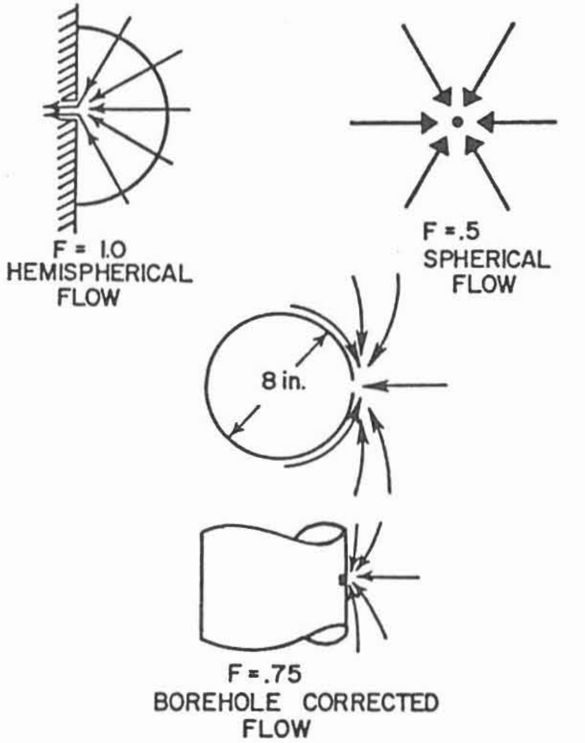
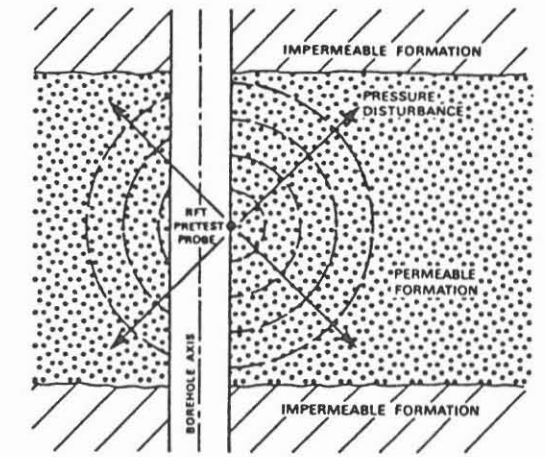
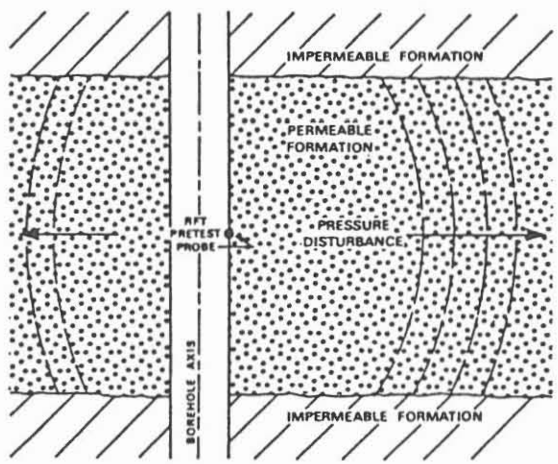
Abb. 8.15



Flow shape factor for various flow pattern.



Spherical propagation of pressure disturbance.



Cylindrical propagation of pressure disturbance.

RFT Flow Pattern and Pressure Propagation

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Abb. 8.16

For the Schlumberger tool with standard probe size set in a 8-inch borehole the permeability is:

$$K_d = 5660 \cdot \frac{q \cdot \mu}{\Delta p}$$

For the Schlumberger Tools with "Large Diameter Probe" the proportionality constant is 2 395 and for the "Large Area Packer" 1 107.

The estimation of permeability from drawdown is mainly effected by the condition of the formation very close to the probe. This could be significantly different from conditions deeper in the formation, because mud invasion has not reached this part.
Limitations are: in very high permeable formation the drawdown pressure might not be high enough to be measured accurately or at very low permeabilities the pressure could drop below bubble point and only "vapor" will be produced giving an erroneous volume.

Permeability from build-up pressure curves

When the two pretest chambers are full, the flow of fluid will be stopped but the pressure will increase and begin to build up to the reservoir pressure. The pressure increase will propagate spherically into the formation until a barrier is reached. If barriers are reached on both sides of the probe, the propagation will become cylindrical. This will change the build-up response. The build-up equation of spherical flow for isotropic permeability is:

$$K_s = 1856 \mu \left(\frac{q_1}{m}\right)^{2/3} \cdot \left(\phi \cdot C_t\right)^{1/3}$$

q_1 = flowrate during first sampling period (cm^3/sec)
m = slope of "straight line" in linear-linear pressure plot
c_t = total compressibility of fluid in uncontaminated formation

In a similar way the equation for build-up with cylindrical flow for horizontal permeability is given:

$$K_c = 88{,}4\mu\left(\frac{q_1}{m \cdot h}\right)$$

h = effective formation thickness

Drawdown and build-up permeabilities could be quite different as with these two techniques we measure different properties of the formation.

- Production Logging

Using downhole measurements for pressures, pressure build-ups, volumes produced within certain times, temperature and recognizing the types of fluid the basis for permeability estimation is given.
Using the appropriate formula for gas or liquid production will result in reliable values.

Conclusion

Remarkable progress has been made over the last few years. New logging systems and evaluation methods have been designed.
However, we have to accept the fact that with wireline logging tools we are only able to measure a "Permeability Index" which still needs to be calibrated against measurements on cores. The only wireline tool providing open hole absolute permeability values is the Repeat Formation Tester. These values are point information and only several tests within the same reservoir could produce an interpolated permeability profile.
The challenge to industry to develop a continuous in-situ measurement system still exists.

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