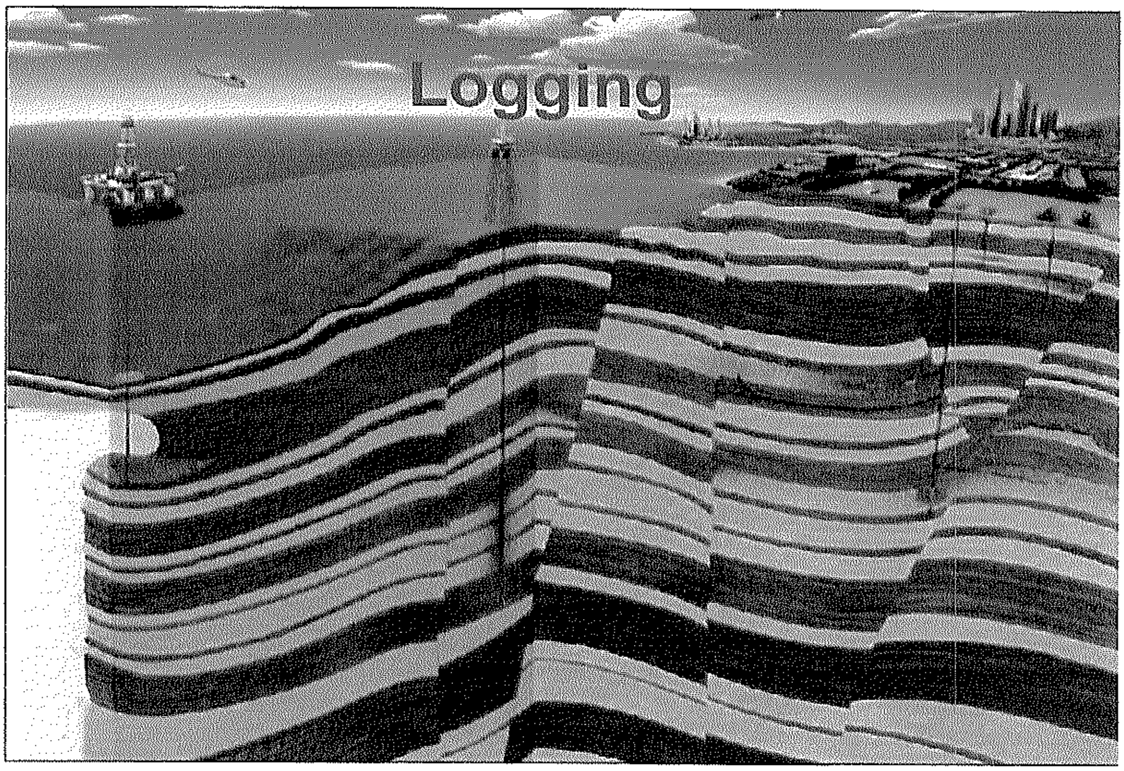
Lecture Note and Document

On 434359

WELL LOGGING



Prepared by

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Petroleum Engineering
School of Geotechnology
Institute of Engineering

434359 WELL LOGGING 2013(3/2555)

COURSE OUTLINES

1. INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)
2. Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)
3. Resistivity Device(2 hrs.)
4. Spontaneous Potential (SP) Log(2 hrs.)
5. Induction Electric and Dual Induction Logs(2 hrs.)
6. Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
7. Quantitative Analysis –Part I (2 hrs.)
8. Density, and Neutron Logs(3 hrs.)
9. Combined Porosity and Lithology logs Determinations(2 hrs.)
10. Focused Resistivity Logs (2 hrs.)
11. Openhole Log and QUICKLOOK Interpretations(3 hrs.)
12. Shaly Sand Interpretations(3hrs.)
13. Case Hole Logging(3 hrs.)
14. Computer Processing of well Logs(1 hr.)
15. Fracture Detection with Well Logs(1 hr.)
16. Dipmeter Principles(2 hrs.)
17. Logs Correlations(2hrs)
18. Special Logs, MWD, LWD(2 hrs.)
19. Core & Core Analysis (2 hrs.)

TEXT BOOKS

1. DOUGLA W. HILCHIE , ***APPLIED OPENHOLE LOG INTERPRETATION,*** (for Geologists and Engineers) Revised 1982.

REFERENCES

1. Zaki Bassiouni, *THEORY, MEASUREMENT, AND INTERPRETATION OF WELL LOGS*, SPE TEXTBOOK SERIES VOL 4@1994.

2.Schlumberger , ‘ LOG INTERPRETATION PRINCIPLES/APPLICATIONS ” 1989

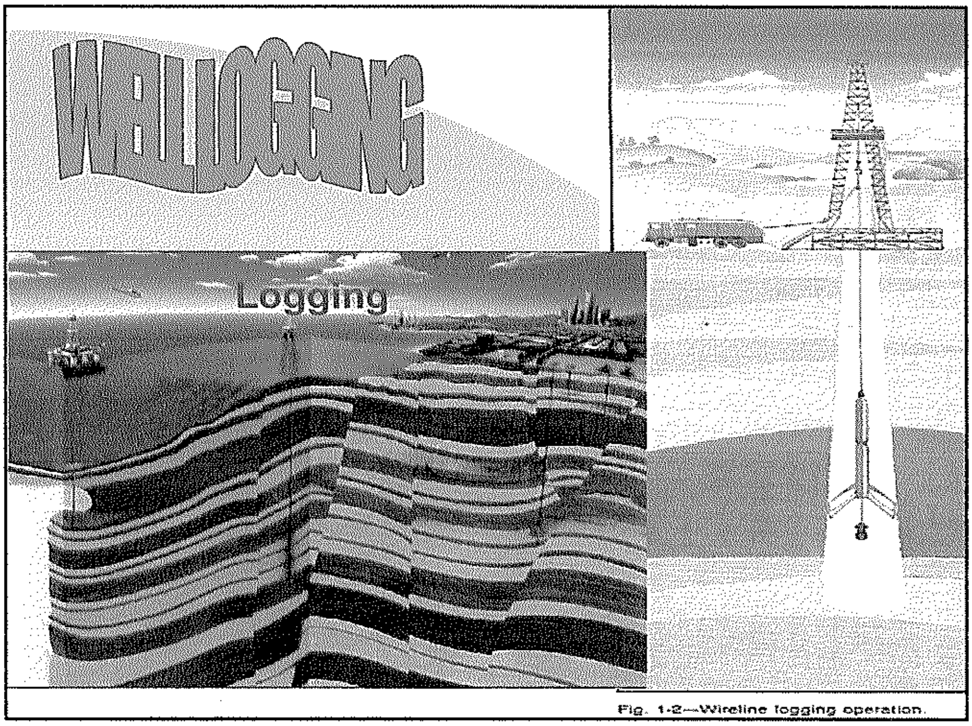
3.M. A. MIAN, “ PETROLEUM ENGINEERING Handbook for the Practicing Engineer ’, Volume I, PennWell Books , 1992

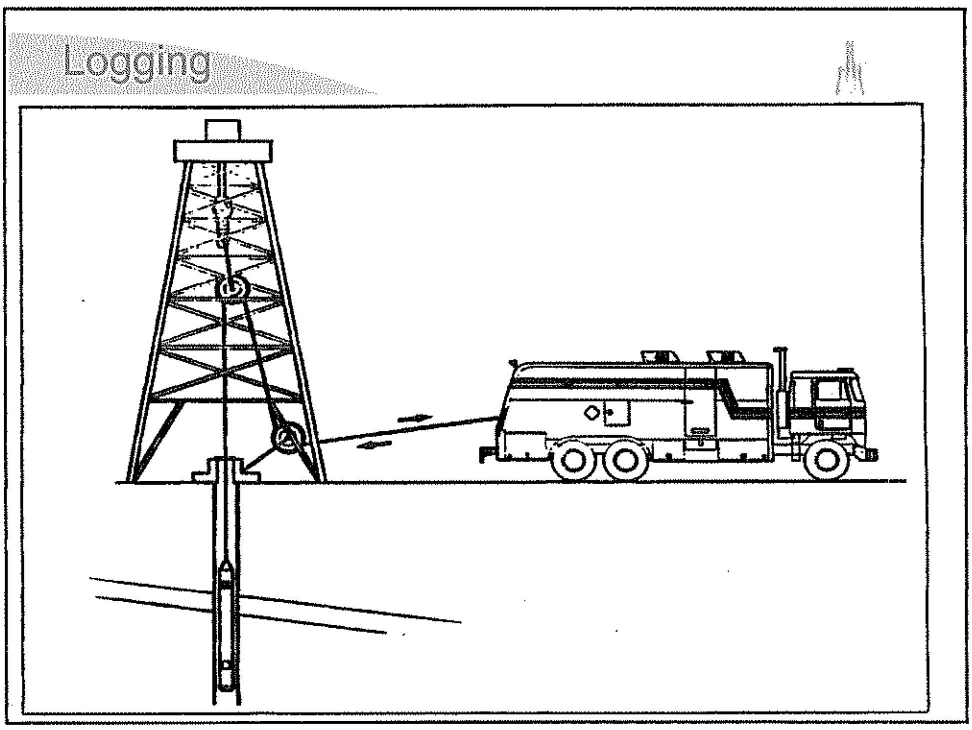
4.Joseph R Hearst, Philip H Nelson, Frederick L Paillett “ WELL LOGGING for Physical Properties” A Handbook for Geophysicists , Geologists, and Engineers , John Wiley & Sons, Ltd. 2000.

5.Petro Canada “ Fundamentals of Core Analysis and Special Core Analysis’, PTT.EP. Training, 1988.

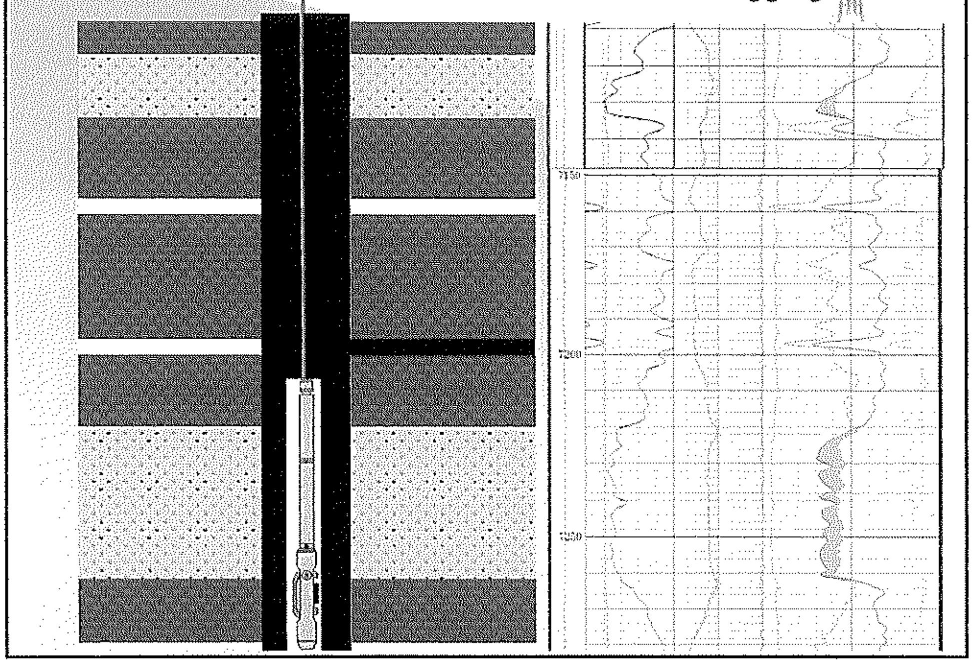
GRADING

Homework	25 %	Quiz I, II	15+15 %
Mid Term	20 %	Final Exam	25 %

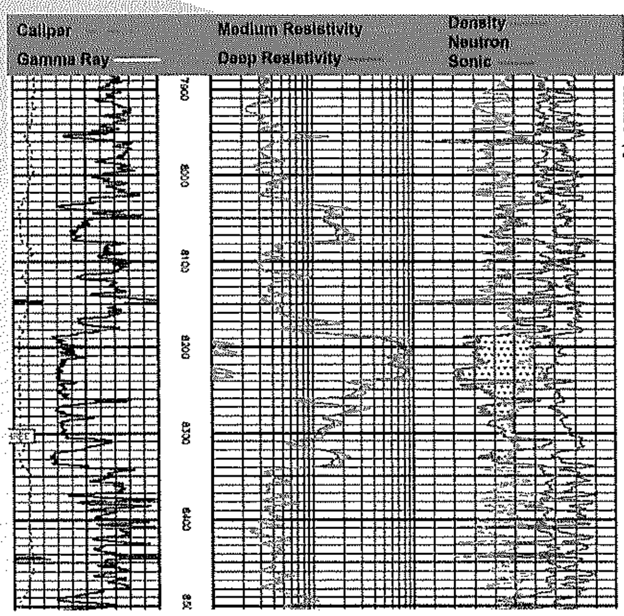

WELLLOGGING
Logging
Fig. 1-2—Wireline logging operation.

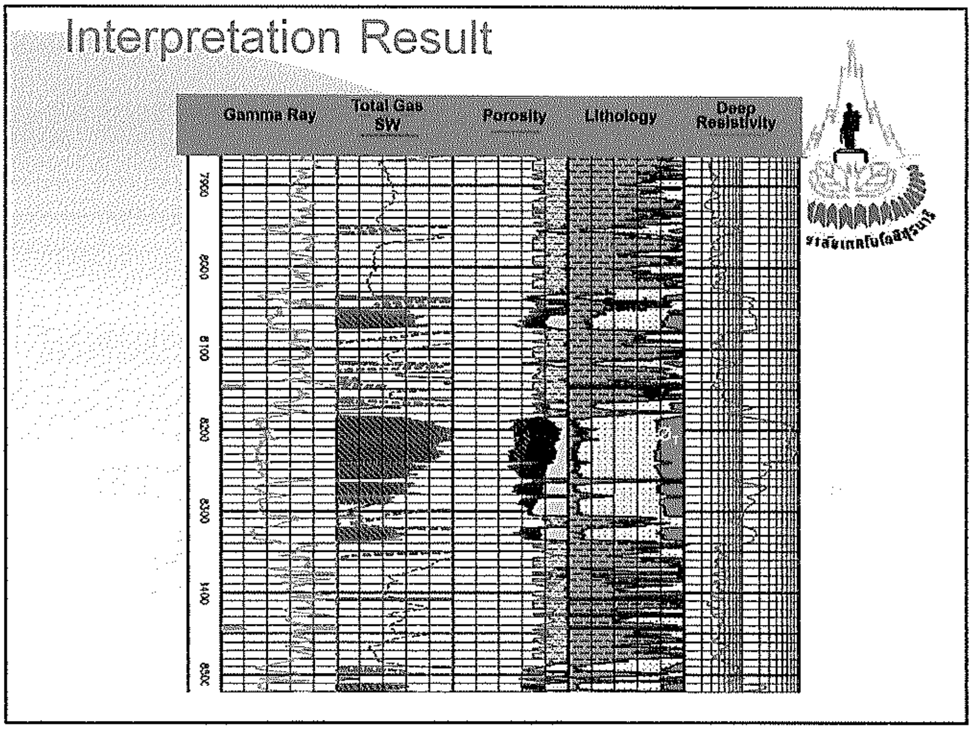

Logging

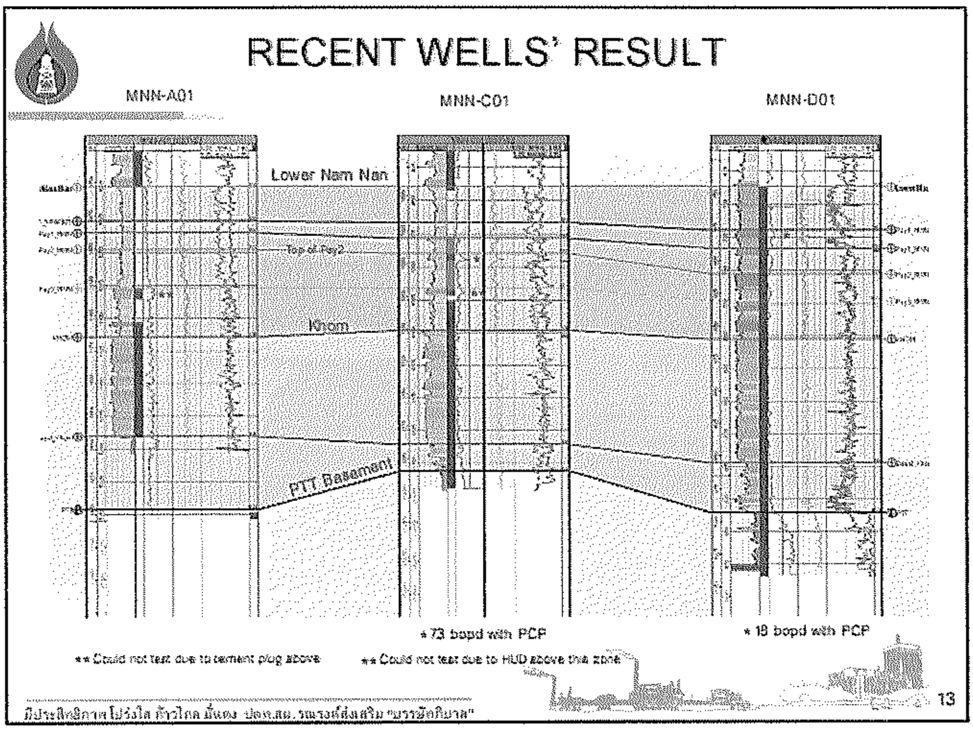
Logging

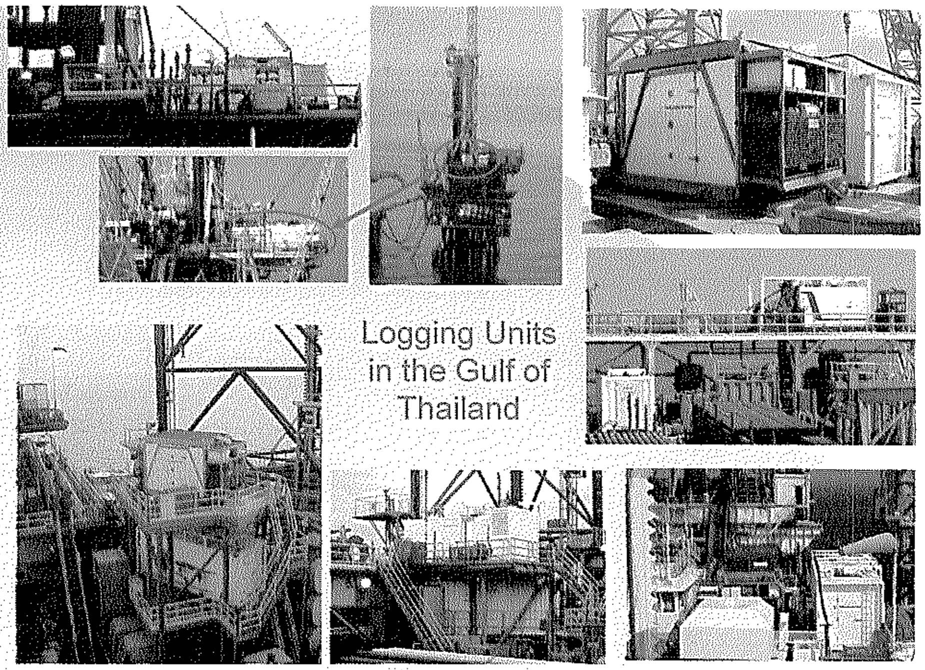


Raw Wireline Log

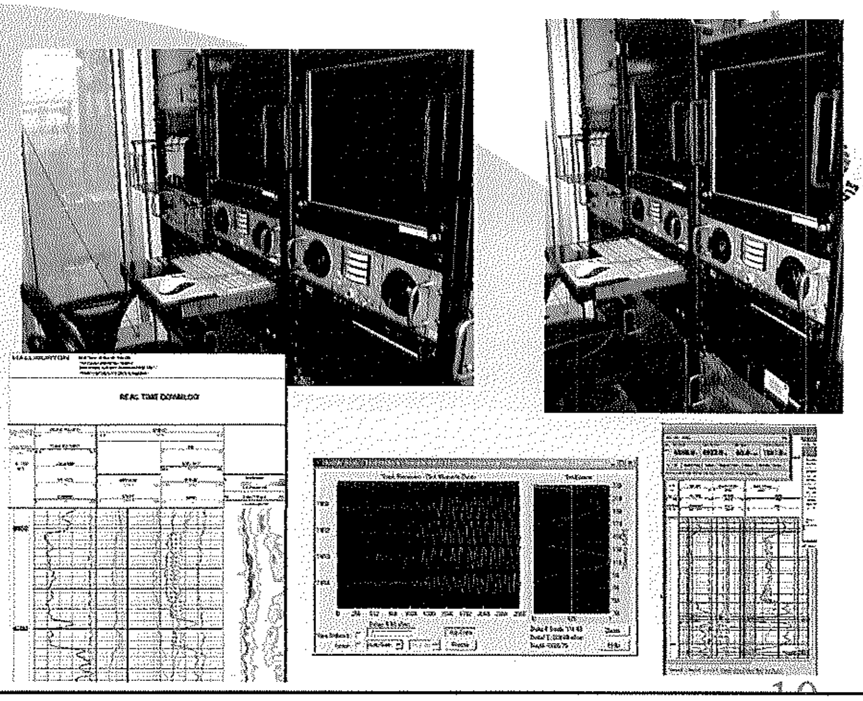



Interpretation Result
Gamma Ray
Total Gas
SW
Porosity
Lithology
Deep
Resistivity
7900
8000
8100
8200
8300
8400
8500

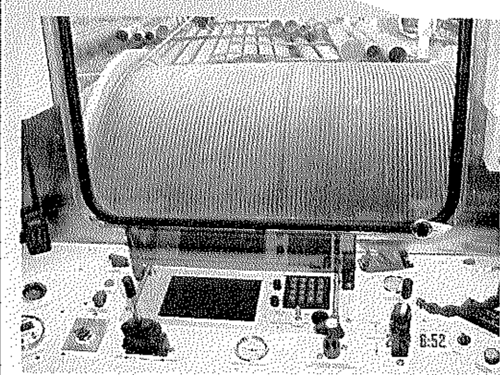

RECENT WELLS' RESULT
MNN-A01
MNN-C01
MNN-D01
Lower Nam Nan
Top of Pay2
Khom
PTT Basement
* 73 bopd with PCP
* 18 bopd with PCP
** Could not test due to cement plug above
** Could not test due to MUD above this zone
13

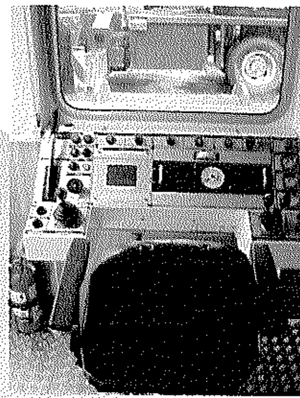


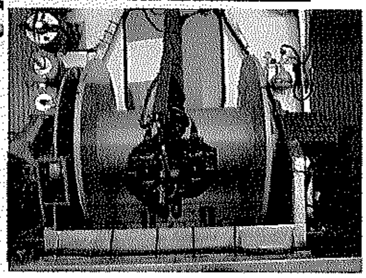
Logging System



Winch Operations







DEVELOPMENTS IN WELL LOGGING

1869 First temperature log Lord Kelvin
1883 Single electrode resistivity log patented by Fred Brown
1912 First surface resistivity survey (Conrad Schlumberger)
1927 First multi-electrode electrical survey in a wellbore (in France)
1929 First electrical survey in California (also Venezuela, Russia, India)
1931 First SP log, first sidewall core gun
1932 First deviation survey, first bullet perforator
1933 First commercial temperature log
1936 First SP dipmeter
1937 First electrical log in Canada (for gold in Ontario)
1938 First gamma ray log, first neutron log
1939 First electrical log in Alberta
1941 Archie's Laws published, first caliper log
1945 First commercial neutron log
1947 First resistivity dipmeter, first induction log described
1948 First microlog, first shaped charge perforator
1948 Rw from SP published
1949 First laterolog
1952 First microlaterolog
1954 Added caliper to microlog
1956 First commercial induction log, nuclear magnetic log described
1957 First sonic log, first density log
1960 First sidewall neutron log (scaled in porosity units)
1960 First thermal decay time log
1961 First digitized dipmeter log
1962 First compensated density log (scaled in density/porosity units)
1962 First computer aided log analysis, first logarithmic resistivity scale
1963 First transmission of log images by telecopier (predecessor to FAX)
1964 First measurement while drilling logs described
1965 First commercial digital recording of log data
1966 First compensated neutron log
1969 First experimental PE curve on density log
1971 First extraterrestrial temperature log Apollo 15
1976 First desktop computer aided log analysis system LOG/MATE
1977 First computerized logging truck
1982 First use of email to transmit data via ARPaNet (predecessor to Internet)
1983 First transmission of log data by satellite from wellsite to computer center
1985 First resistivity microscanner

What Is A Log?

A log is a record of a voyage, like a ship's log or a travelog. A well-log is a record of the voyage of a measuring instrument into a well bore. The instrument itself is sometimes called a log, but it really is a logging tool. The "log" is the paper or digital recording of the measurements made by the logging tool, versus depth or time.

What Is Petrophysics?

Petrophysics is the study of the physical and chemical properties of rocks and their included fluids, based on well log measurements, laboratory data, and the fundamental laws of math and physics.

FORMATION EVALUATION

1. WELL LOGGINGS

Driller's Logs, Mud Logs

ELECTRIC WIRE LINE LOGS

2. CORE ANALYSIS

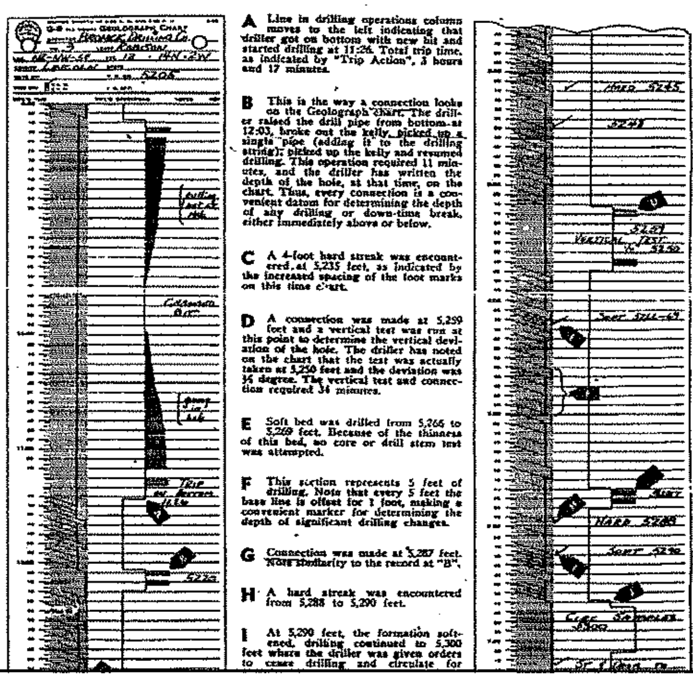
3. WELL TESTING

Repeated Formation Tester(RFT)

Drill Stem Test (DST)

Production Test (PT)

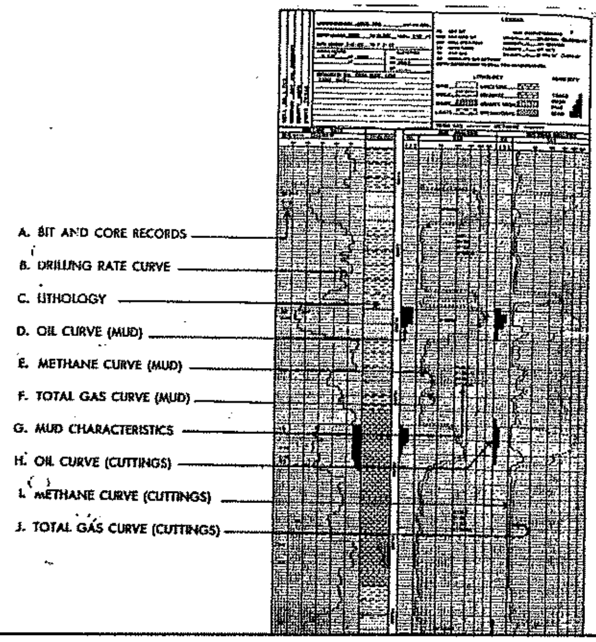
Fig 9.1 Typical mechanical drilling log record

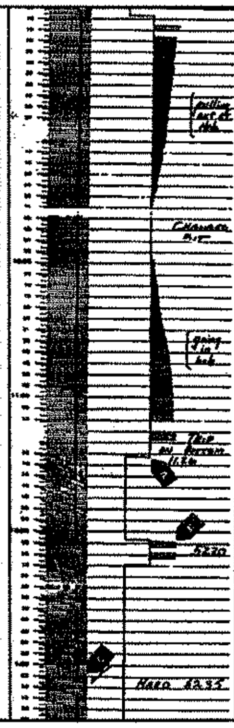


Driller"s Logs,

Fig 9.12 Mud Logging Report

Mud Logs





er raised the drill pipe from bottom at 12:03, broke out the kelly, picked up a single pipe (adding it to the drilling string), picked up the kelly and resumed drilling. This operation required 11 minutes, and the driller has written the depth of the hole, at that time, on the chart. Thus, every connection is a convenient datum for determining the depth of any drilling or down-time break, either immediately above or below.

C A 4-foot hard streak was encountered at 5,235 feet, as indicated by the increased spacing of the foot marks on this time chart.

D A connection was made at 5,259 feet and a vertical test was run at this point to determine the vertical deviation of the hole. The driller has noted on the chart that the test was actually taken at 5,250 feet and the deviation was ½ degree. The vertical test and connection required 34 minutes.

E Soft bed was drilled from 5,266 to 5,269 feet. Because of the thinness of this bed, no core or drill stem test was attempted.

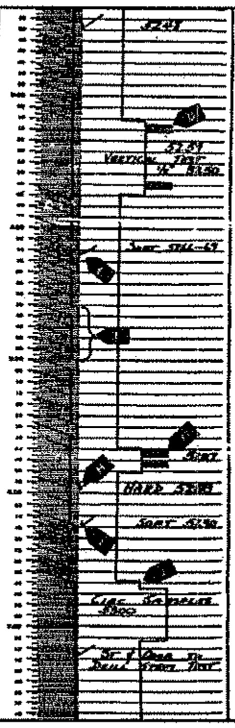
F This section represents 5 feet of drilling. Note that every 5 feet the base line is offset for 1 foot, making a convenient marker for determining the depth of significant drilling changes.

G Connection was made at 5,287 feet. Note similarity to the record at "B".

H A hard streak was encountered from 5,288 to 5,290 feet.

I At 5,290 feet, the formation softened, drilling continued to 5,300 feet where the driller was given orders to cease drilling and circulate for samples.

J Circulating for samples started at 6:39 as indicated by movement of



Why Log A Well?

In 1942 G. E. Archie of Shell developed the following equation that is known as ARCHIE EQUATION.

WATER SATURATION EQUATION

$$\boxed{S_w = c\sqrt{R_w / R_t} / \phi}$$

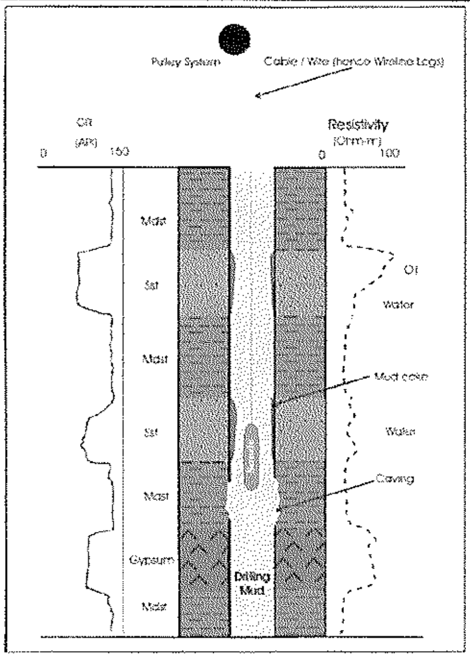
Where c = 1.0 for carbonates and 0.90 for sands.

This is the basic equation of log interpretation. <u>The whole well-logging industry is built upon this equation.</u>

The equation shows that hydrocarbons in place can be evaluated if there are sufficient logs to give interstitial water resistivity (R_w), formation resistivity (R_t), and Porosity (ϕ). In practice Rw is obtained either from applying the equation in a nearby water sand ($S_w = 1$) or from the SP log or from catalogs or water sample measurements; and ϕ is obtained from porosity logs (Density, Neutron, or Sonic). R_t is obtained from deep resistivity readings (Induction or Laterolog).

Why Resistivity

- Distinguish between water-bearing and hydrocarbon-bearing formations
- Determine true formation resistivity (R_t) for calculating uninvaded zone water saturation (S_w)
- Estimate diameter of invasion
- Indicate moveable hydrocarbons

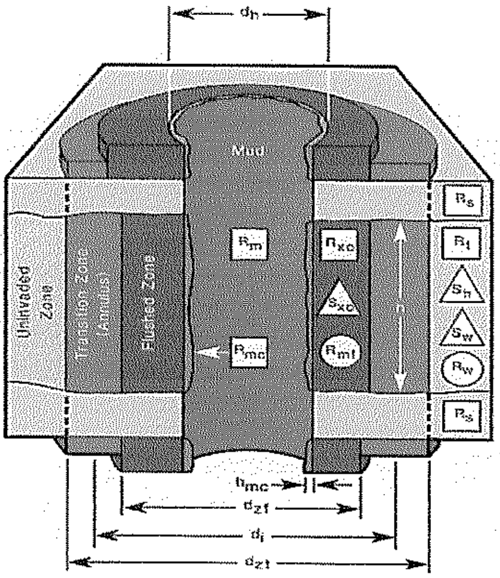


Sonde lowered down borehole on a cable, then slowly pulled back up. The response from the various tools is recorded in real-time on computers at the surface. A number of tools to be run together at the same time, called a "combo" tool.

The resistivity of some materials

Material	Resistivity (Ω-m)
Marble	$5\times10^{7} \rightarrow 10^{9}$
Quartz	$10^{12} \rightarrow 3\times10^{14}$
Petroleum	2×10^{14}
Distilled water	5×10^{3}
Clay / Shale	$< 2 \rightarrow 10$
Salt water-bearing sand	$0.5 \rightarrow 10$
Oil-bearing sand	$5 \rightarrow 10^{3}$
"Tight" limestone	10^{3}

Some definitions



h : Bed Thickness
h_{mc} : Mudcake Thickness
d_i : Diameter of Invasion (step profile)
d_h : Borehole Diameter
d_{zf} : Diameter of Flushed Zone
d_{zt} : Diameter of Transition Zone

S_h : Hydrocarbon Saturation
S_w : Water Saturation
S_{xo} : Flushed Zone Water Saturation
S_{hr} : Residual Hydrocarbon Saturation

R_m : Mud Resistivity
R_{mc} : Mudcake Resistivity
R_{mf} : Mud Filtrate Resistivity
R_s : Adjacent Bed Resistivity
R_t : True Resistivity
R_{xo} : Flushed Zone Resistivity
R_w : Formation Water Resistivity

WATER SATURATION EQUATION

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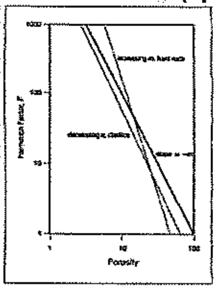
Archie's Experiments

Log-Log plot of F vs Porosity



Archie found that laboratory measurements of F could also be related to the porosity of the rock by an equation of the form,

$$F_r = \frac{a}{\Phi^m}$$

Where a and m are experimentally determined constants; a is usually close to 1 and m is usually close to 2

Log(F) = Log(a) – m*Log(Phi)

Calculate Rwa based on Archie equations

$$F_r = \frac{R_o}{R_w} \qquad F_r = \frac{a}{\Phi^m}$$

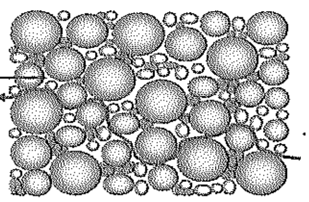
$$R_w = \frac{R_o}{F} = \left(\frac{R_o}{a}\right)\phi^m$$

Hence in a 100% water bearing interval we can calculate Rw if we know porosity and the measured resistivity. Assuming we know the constants a and m

Resistivity (r)

Now add oil to that formation...
Oil is an insulator

R_w



$R_T > R_0$

Where

Ro is the wet formation resistivity

Rt is the true resistivity

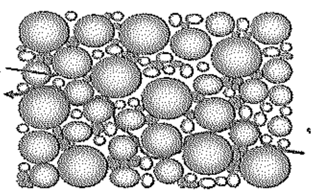
Resistivity (r)

$R_T = f(R_w$, amount of water, amount of oil)

$$S_w = \frac{R_0}{R_T}$$

$$S_w \approx \frac{R_w}{\phi * R_T}$$

R_w



The Archie Equation

Tortuosity Factor and Cementation Exponent

Formation Water

$$S_w = \sqrt[n]{\frac{a}{\Phi^m} \times \frac{R_w}{R_t}}$$

Saturation Exponent

Porosity

Uninvaded Zone Resistivity

Archie Equation

		Lithology assumptions	Core Analysis	Logs
n	Saturation Exponent	YES	YES	
a	Tortuosity Factor	YES	YES	
Φ	Porosity		YES	Density, Neutron, Acoustic, NMR
m	Cementation Exponent	YES	YES	
R_t	Formation Resistivity			Induction, Laterolog (deep)

ROUTINE CORE ANALYSIS

A. POROSITY MEASUREMENT

BULK VOLUME
- LIQUID DISPLACEMENT
- CALIPERING & CALCULATIO

SUMMATION OF FLUID

GAS TRANSFER
-BOYLE'S LAW POROSIMETER

LIQUID RESATURATION
TOLOENE , KOBE POROSIMETER

GRIAN DENSITY
-BOYLE'S LAW

MEASUREMENT φ UNDER CONFINING PRESSURE
HYDROSTATIC LOAD CELL

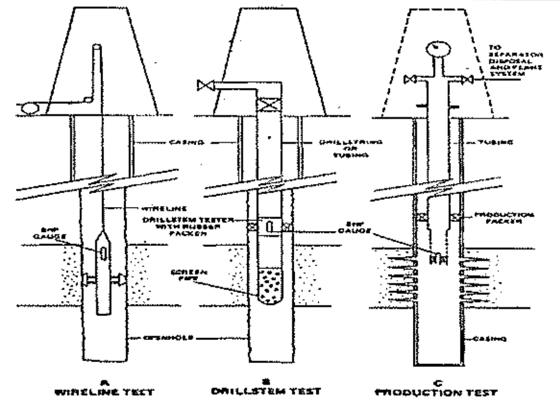


Fig.10.1 Test Techniques

1. ROCK & FLUID PROPERTIES

1.1 ROCK PROPERTIES

POROSITY

PERMEABILITY

SATURATION

WETTABILITY

COMPRESSIBILITY

FORMATION FACTOR

1. Porosity
   A. Absolute porosity
   B. Effective porosity
   1. Primary porosity
   2. Secondary porosity

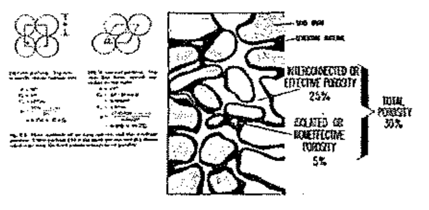


Figure 1.18 Effective, non-effective and total porosity

Reservoir Rock Properties

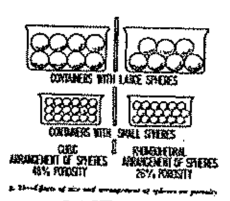
A. POROSITY

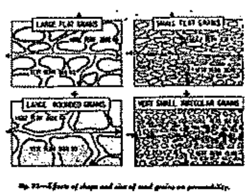
= φ = volume of pore / Bulk volume

- Absolute porosity
- Effective (interconnected) porosity
- Primary porosity
- Secondary porosity

B. SATURATION

Sw = Volume of water/Volume of pore
So = Volume of oil/Volume of pore
Sg = Volume of gas/Volume of pore





Q: Rate of Flow, cc/sec.
ΔP: Pressure Differential, Atmospheres
A: Area, cm^2
μ: Fluid Viscosity, Centipoise
L: Length, cm
K: Permeability, Darcies

$$Q = \frac{K \Delta P A}{\mu L}$$

Fig 1.20 Permeability

$$\frac{Q\mu\Delta L}{A\Delta P}$$

- Absolute
- Effective
- Relative $\frac{k_{ew}}{k}$ $\frac{k_{eo}}{k}$

D. WETTABILITY
- Water wet
- Oil wet

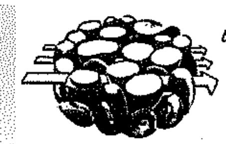
E. FORMATIOM COMPRESSIBILITY

$Cf = 1.87 \times 10^{-6} \times \phi^{-0.415}$ by Hall Humble

$= -\left(\frac{1}{V}\right)\left(\frac{dV}{dp}\right)$

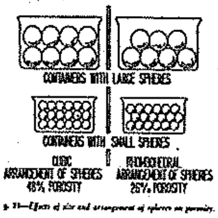
F. FORMATION FACTORS

$F = Ro/Rw = a/\phi^m$

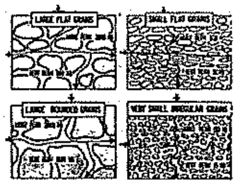


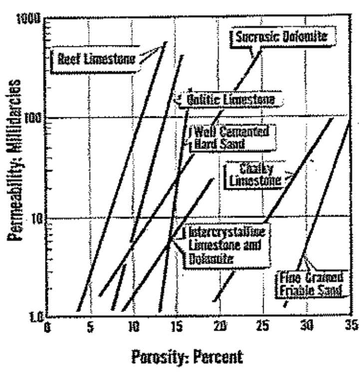
Q: Rate of Flow, cc/sec.
ΔP: Pressure Differential, Atmospheres
A: Area, cm²
μ: Fluid Viscosity, Centipoise
L: Length, cm
K: Permeability, Darcies

Figure 1.24 Permeability $Q = \frac{K\Delta PA}{\mu L}$

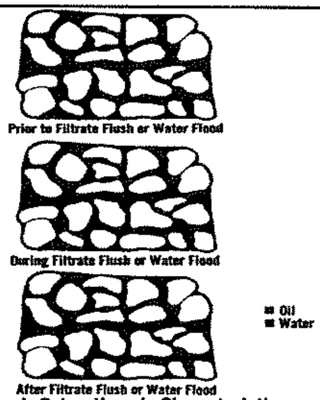


Size + shape
Arrangement
Compaction
Cementation
Grain kind



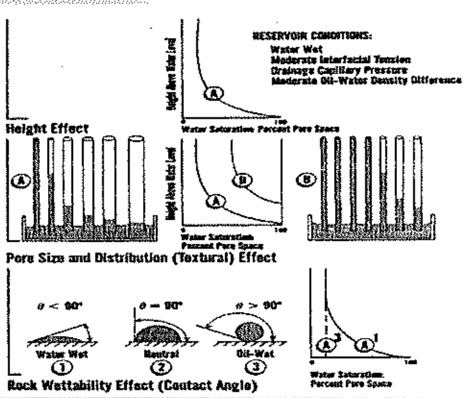


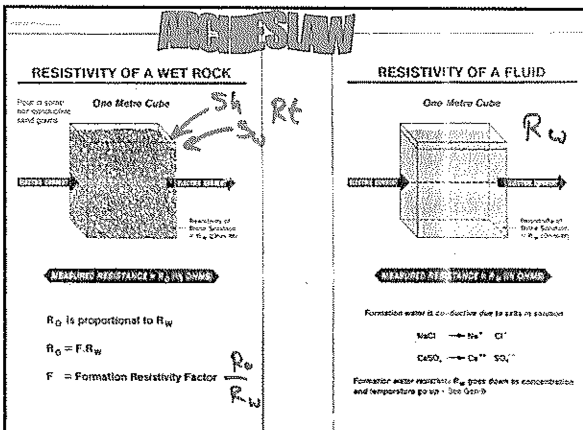
Permeability and Porosity Trends For Various Rock Types

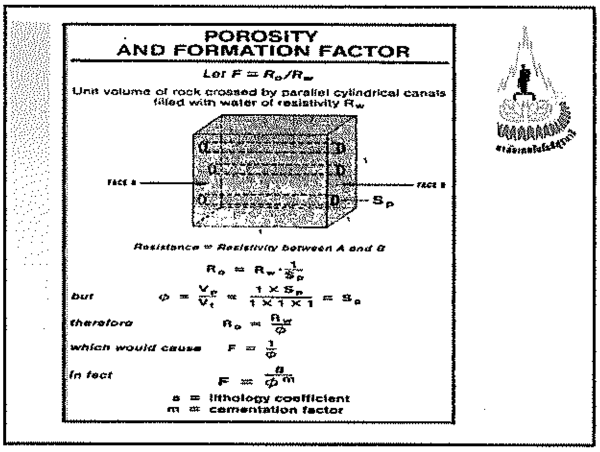


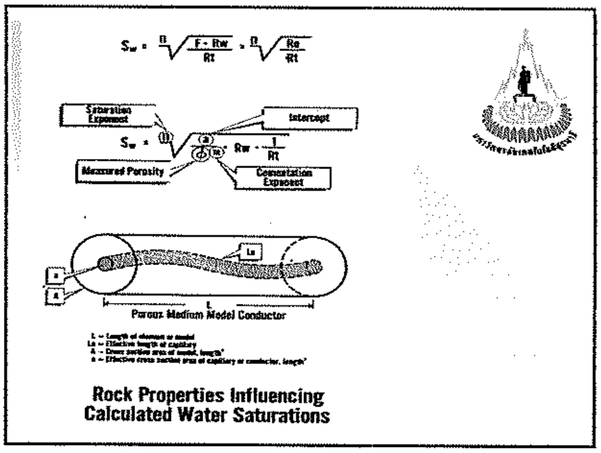
Reservoir Saturations in Characteristic Sand During Oil Displacement by Water

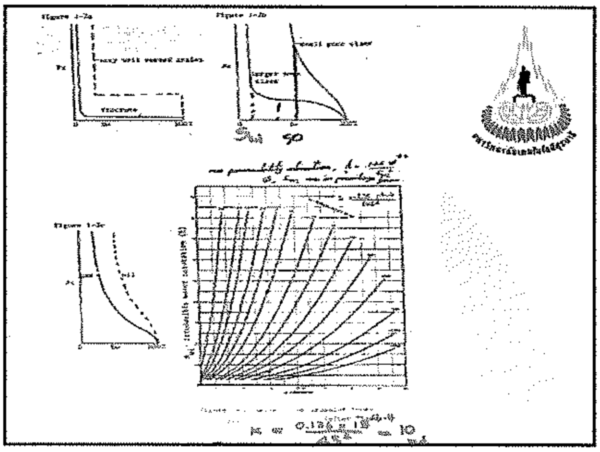
Rock Properties

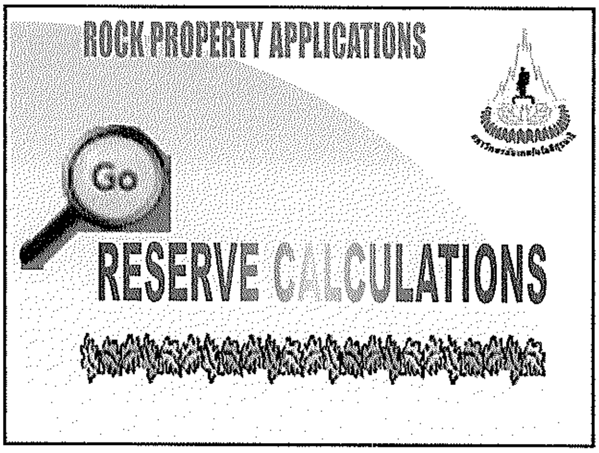





POROSITY
AND FORMATION FACTOR
Let F = Ro/Rw
Unit volume of rock crossed by parallel cylindrical canals filled with water of resistivity Rw
Resistance = Resistivity between A and B
Ro = Rw · 1/Sp
but φ = Vp/Vt = 1 × Sp / 1 × 1 × 1 = Sp
therefore Ro = Rw/φ
which would cause F = 1/φ
in fact F = a/φ^m
a = lithology coefficient
m = cementation factor


Saturation Exponent
Intercept
Measured Porosity
Cementation Exponent
Porous Medium Model Conductor
Rock Properties Influencing
Calculated Water Saturations




ROCK PROPERTY APPLICATIONS
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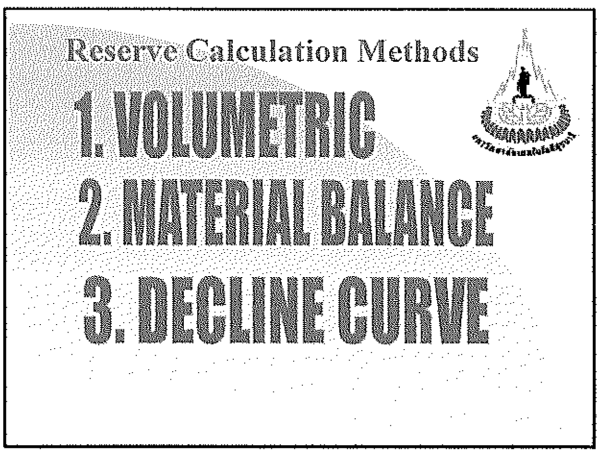
RESERVE CALCULATIONS


Reserve Calculation Methods
1. VOLUMETRIC
2. MATERIAL BALANCE
3. DECLINE CURVE

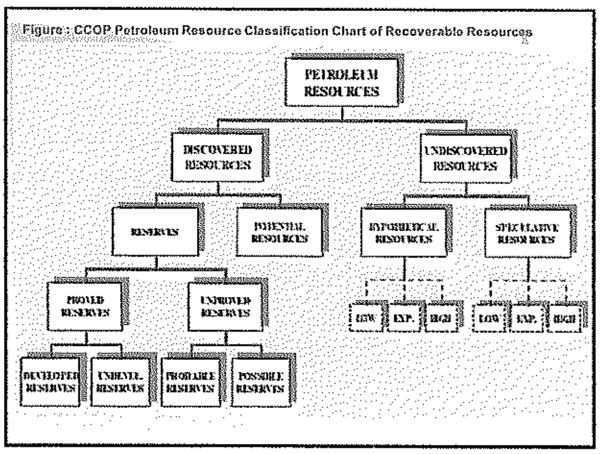
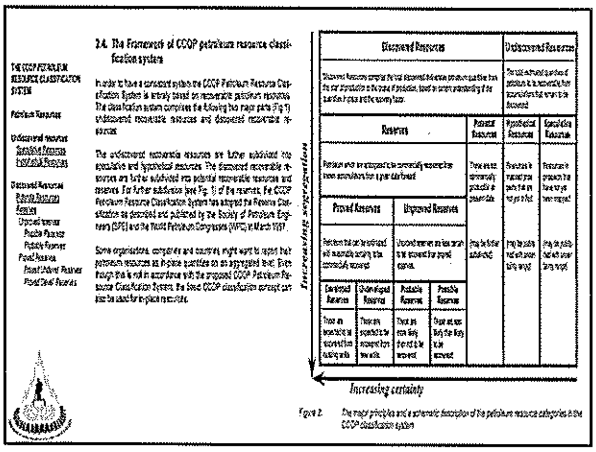
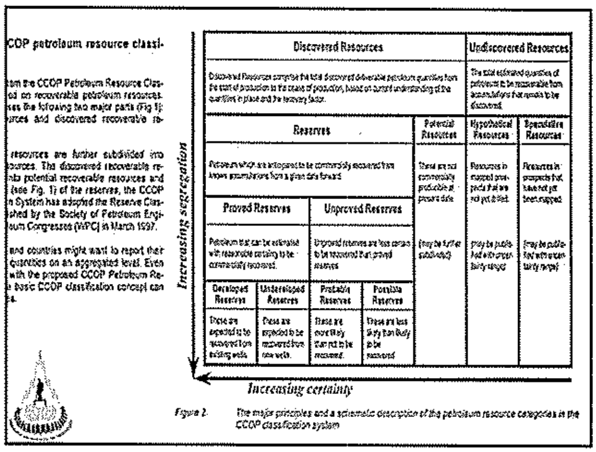


Figure : CCOP Petroleum Resource Classification Chart of Recoverable Resources
PETROLEUM RESOURCES
DISCOVERED RESOURCES
UNDISCOVERED RESOURCES
RESERVES
POTENTIAL RESOURCES
HYPOTHETICAL RESOURCES
SPECULATIVE RESOURCES
PROVED RESERVES
UNPROVED RESERVES
LOW
EXP.
HIGH
LOW
EXP.
HIGH
DEVELOPED RESERVES
UNDEVEL. RESERVES
PROBABLE RESERVES
POSSIBLE RESERVES





PROVED RESERVE

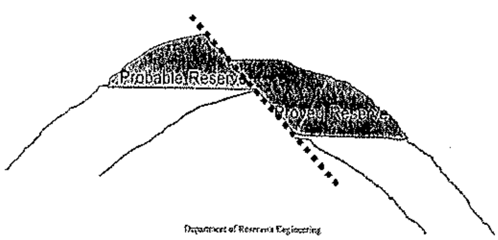
- Commercially Recoverable
  - Geological, Engineering And Economic Data, Rule & Regulation
  - Operating Methods
  - Developed/ Undeveloped
  - Price, Cost, Time Span Of Development
  - Deterministic (High Degree Of Confidence)
  - Probabilistic (90% Probability >= The Estimate)

PROBABLE RESERVE

- More Likely Than Not To Be Recoverable
- Step-Out Drilling/ Inadequate Subsurface Control
- Well Log/No Core Test/No Analogous To Proved Or Producing Area
- In Fill Which Can Be Proved If Approved
- Improved Recovery/Adjacent to Proved Area/Workover/Incremental From Volumetric Estimation
- 50-90% Confidence

PROBABLE RESERVE

- Separated From Proved Area By Faults And In The Higher Structure

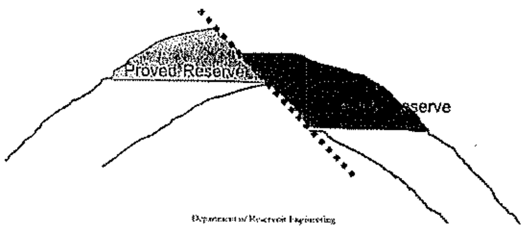


POSSIBLE RESERVE

- Less Likely To Be Recoverable
- 10-50% Confidence
- Supported By Geo/ Eng/ Eco Data But Beyond Probable Areas
- Log /Core Not Productive @ Commercial Rate
- Infill Drilling Subject To Uncertainty
- Improved Recovery

POSSIBLE RESERVE

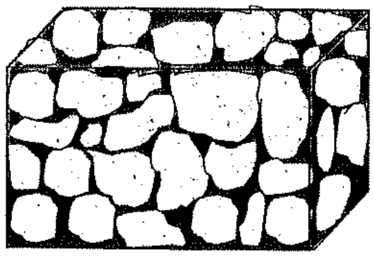
- Adjacent To Proved Areas, Separated By Faults But In Lower Structure



Reserves Estimation Methodology

Volumetric Calculation

Reserves = Bulk Volume . ϕ . So . Bo . Rf



ϕ = Porosity

So = Saturation

Bo = Volume Factor

Rf = Recovery Factor

Volumetric Estimates

- Reserves = Reservoir Volume x Porosity x Oil Saturation x Recovery Factor x Shrinkage to Surface Conditions
- In oilfield units:

Reserves = [7758 x A x h x ø x (1-S_w) x R]/Bo

where Or 43560 for gas or Bg

7757	= bbls/acre-ft
A	= area (sq. ft) or Acre
h	= net thickness (ft)
ø	= porosity (fraction)
S_w	= water saturation (fraction)
R	= recovery factor (fraction)
Bo	= formation volume factor
Bg	= Gas formatiom volume factor

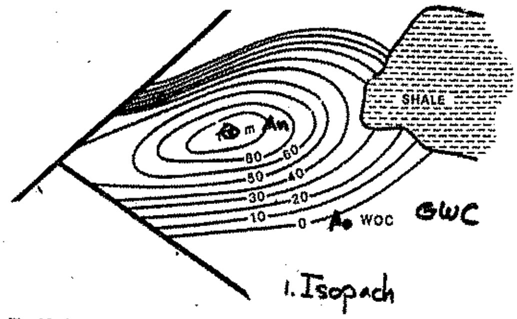


Fig. 4.3. *Isopay map for a hydrocarbon-bearing pool*

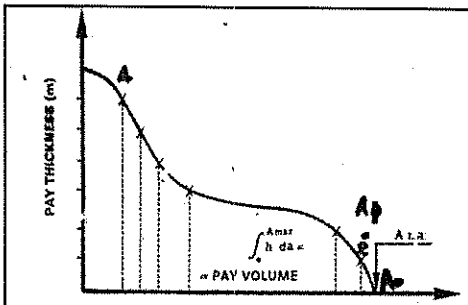
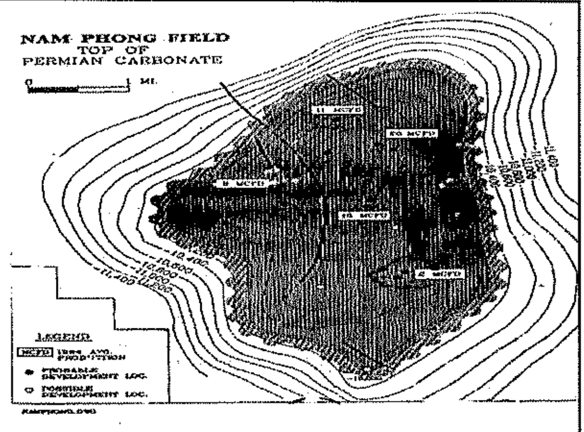


Fig. 4.4. *Graphical method for the calculation of the net pay volume. From Ref permission of Kluwer Academic Publishers and of Professors Archer and Wall*

Isobath contour map of the top of a hydrocarbon-bearing pool

Fig. 4.2. *The hydrocarbon-bearing volume plotted against depth. From Ref. 4, reprinted with permission of Kluwer Academic Publishers and of Professors Archer and Wall*



Rock Volume Calculation

1. Trapezoidal Rule

$$V_b = h\left[\tfrac{1}{2}(A_0+A_n)+(A_1+A_2+A_3+\cdots+A_{n-1})\right]$$

$\frac{A_1}{A_0} > 0.5$

2. Pyramidal Rule

$$V_{b_n} = \frac{h}{3}\left(A_n + A_{n+1} + \sqrt{A_n \cdot A_{n+1}}\right)$$

$\frac{A_1}{A_0} < 0.5$

3. Simpson's Rule

$$V_{B_n} = \frac{h}{3}\left(A_{n-1} + A_n + A_{n+1}\right)$$

Simpson's rule(if the numbers of contours are even)

$$V_B = h/3[(y_0+y_n)+4(y_1+y_3+\dots+y_{n-1})+2(y_2+y_4+\dots+y_{n-2})]$$

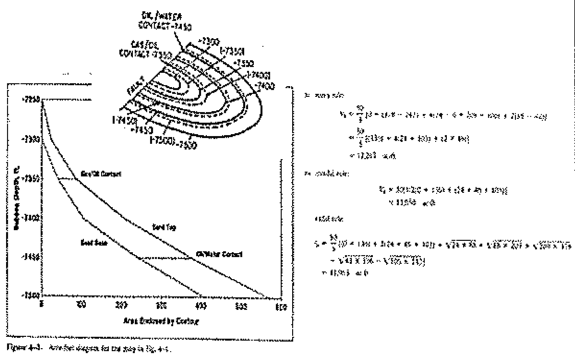
Trapezoidal rule(with some what less accuracy)

$$V_B = h[1/2(y_0+y_n)+y_1+y_2+\dots+y_{n-1}]$$

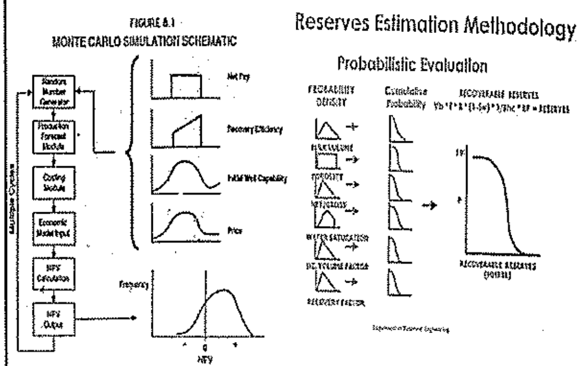
Pyramidal rule(if $A_{n+1}/A_n<0.5$)

$$V_B = h/3(A_n+A_{n+1}+\sqrt{A_nA_{n+1}})$$

How To Calculate Formation Volume (Cond.)



Monte Carlo Simulations



3.7 Reservoir Performances

Prior to drilling, the reserve may be estimated by reservoir structure size comparison with the previous discovered reservoir, but after exploratory drilling the volumetric method will be applied. After production begins, the reservoir performance will be collected and the more accurate methods will be applied to determine gas(or petroleum) reserve.

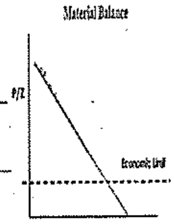
3.7.1 Decline Curves

When the production data has been collected for some time (cumulative production about 5-10% of the gas in place) then the "*Decline Curve*" method can be applied to give the more accurate results. Specially for gas, P/Z V.S. G_p (cumulative production from material balance equation)) plot can be projected as a straight line to the economic limit and get the reserve.

Production Decline Analysis

Reserves Estimation Method

Material Balance



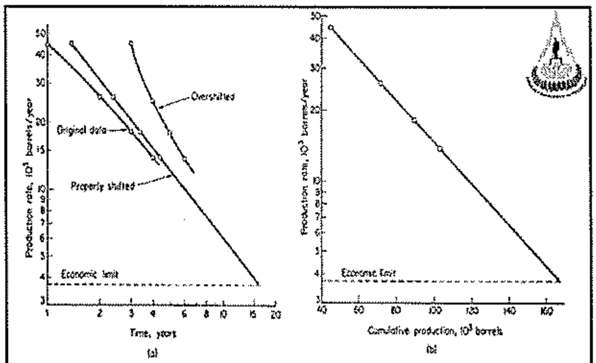


Figure 11.7. Harmonic decline example. (a) Rate versus time on log-log plot. (b) Rate versus cumulative on semilog plot.

Water saturation-porosity relationships For productive carbonates are considerably more variable than in sandstones. Although 60% Sw is usually the cut-off some carbonates are productive at 70% Sw and others produce water at 30% Sw. Experience in an area and a particular zone is necessary to establish realistic cut-offs.

In carbonates it is often the case that low permeability zones which will produce nothing separate reservoirs. These low permeability zones are usually characterized as low porosity and high water saturation.

Example 1-1 shows an analysis of a continuous 100 feet of limestone with no shale breaks. The separate reservoirs are marked as well as the hydrocarbon-water contacts.

Example 1-1 Interpretation of a Limestone Sw φ Data

Sw%	φ%	Thickness (ft)	Interpretation
100	2	10	wet and non-permeable
100	8	5	will probably produce water
100	3	7	non-permeable
30	9	11	hydrocarbon reservoir
80	11	9	will produce water -hyd./wtr cont.
95	3	22	non-permeable
90	8	36	will produce water

1-7

$V = A\,B\,\Sigma(h_i\,(1-Sw_i)\,\phi_i)$
$= A\,B\,(h_1(1-Sw_1)\,\phi_1 + h_2\,(1-Sw_2)\,\phi_2 + h_3\,(1-Sw_3)\,\phi_3 + \cdots)$ (1-8)

where A = area drained in acres
B = 43560 when V is in cubic feet or 7758 when V is in barrels
h = thickness in feet
1,2,etc are layers of the reservoir having different properties.

To calculate an average porosity or water saturation for the reservoir equations 1-9 and 1-10 are used.

$\phi_{avg.} = \frac{\Sigma(\phi_i\,h_i)}{\Sigma(h_i)}$ (1-9) $Sw_{avg.} = \frac{\Sigma(Sw_i h_i)}{\Sigma(h_i)}$ (1-10)

Example 1-2 shows an example of these equations in use.

Example 1-2 Volumetric and Average Calculations
The reservoir has three zones or layers with different water saturations and porosities

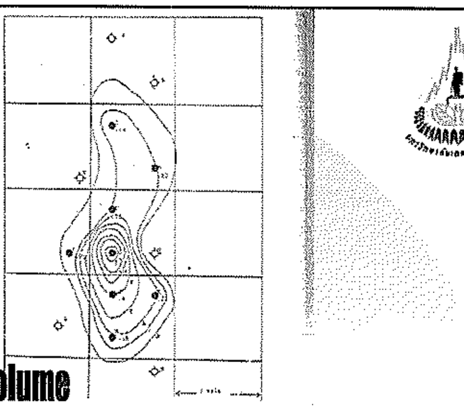
zone	Sw%	φ%	h(ft)
1	25	22	4
2	33	27	6
3	20	29	10

area = 40 acres (A)
oil bearing so B = 7758
V is in barrels

$V = 40 \times 7758\ (4 \times (1-.25).22 + 6 \times (1-.33).27 + 10 \times (1-.20).29)$
$= 40 \times 7758\ (.660 + 1.085 + 2.320)$
$= 1,261,250$ bbls.(or in practical units 1,261,000 bbls)

$\phi_{avg.} = (22 \times 4 + 27 \times 6 + 29 \times 10) \div (4 + 6 + 10) = 27\%$

$Sw_{avg.} = (25 \times 4 + 33 \times 6 + 20 \times 10) \div (4 + 6 + 10) = 25\%$



Isovolume

Figure 4-3. Isovolume map of lower cretaceous oil field structure of D. W. Hibbs, Inc. South Colorado. Isopach

Example 1-3 Contour Interval 10' Isopach map.

(Oil) thickness (contour)	Area (Acres)	
0	1776	A_0
10	1021	A_1
20	436	A_2
30	302	
40	155	
50	93	
60	45	
70	10	A_n

Solution (Assume φ, B_o, S_w = 1)

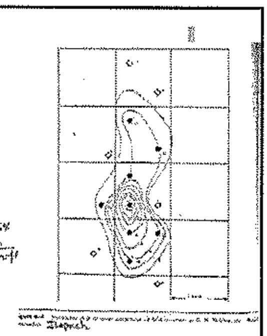
$V = H\left(\frac{A_0}{2} + A_1 + A_2 + \cdots + \frac{A_n}{2}\right) \times 7758\ \frac{bbls}{Acre\text{-}ft}$

$V = 10\left(\frac{1776}{2} + 1021 + 436 + 302 + 155 + 93 + 45 + \frac{10}{2}\right) \times 7758$

$= 227,900,000$ bbls

Assume φ = 0.27, S_w = 0.25
STB

oil in place
= 0.27 × (1−0.25) × 227,900,000
= 46,149,500/B_o bbls Ans



Isopach

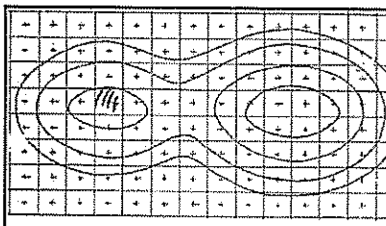


Figure 5. Example grid for hand integration of contour maps.

The equations to be used are:

43560

Oil, bbls = 7758 $\sum_{j=1}^{n}$ ... / B_o

Gas, SCF = 43560 $\sum_{j=1}^{n}$ ... / B_g

St.F

where j = subscript indicating value from the jth element,
A = area, acres,
h_t = gross pay thickness, feet,
N/G = net-to-gross ratio, fraction,
φ = porosity, fraction,
S_w = average water saturation, fraction,
B_o = oil formation volume factor, res. barrels / STB, and
B_g = gas formation volume factor, res. cubic feet / SCF,

Equations (5) and (6) are better approximations than are equations (1) and (2) to the actual volume of hydrocarbons in place. The results ...

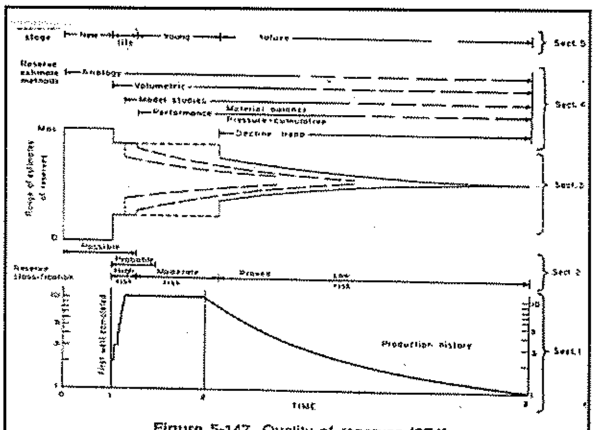


Figure 5-147. Quality of reserves [274].

RESERVOIR VOLUME DETERMINATIONS FROM ISOCHORE MAPS

Two methods are commonly used to determine reservoir volume from net pay isochore maps, the **Horizontal Slice Method** and the **Vertical Slice Method**.

HORIZONTAL SLICE

Horizontal Slice Method

One way to determine volume of a reservoir is to *horizontally* slice the depicted reservoir solid, and sum the volumes of the layers to calculate total volume of the reservoir. For the horizontal slice method, two equations are generally used to determine the volume from a net pay isochore map that has been planimetered (Craft and Hawkins 1959). The first determines the volume of the frustum of a pyramid.

$$\text{Volume} = \frac{1}{3}h(A_n + A_{n+1} + \sqrt{A_n A_{n+1}}) \qquad (14\text{-}1)$$

where

h = Interval thickness between isochore lines
A_n = Area enclosed by lower value isochore line
A_{n+1} = Area enclosed by higher value isochore line

This equation is used to determine the volume of a layer between successive slices, which are based on vertical thickness and represented on the map by net pay contour lines (*Fig.* 14-40). The total volume of the reservoir is the sum of these separate volumes.

The second equation used in the horizontal slice method determines the volume of a trapezoid.

$$\text{Volume} = \frac{1}{2}h(A_n + A_{n+1})$$

$$\text{Volume} = \frac{1}{2}h(A_n + A_{n+1})$$

or, for a series of successive trapezoids,

$$\text{Volume} = \frac{1}{2}h(A_0 + 2A_1 + 2A_2 \ldots 2A_{n-1} + A_n) + t_{avg}A_n \qquad (14\text{-}2)$$

where

A_0 = Area enclosed by the zero isochore line
$A_1, A_2 \ldots A_n$ = Areas enclosed by successive contour lines
t_{avg} = Average thickness within the maximum thickness contour line

The pyramidal equation usually provides the most accurate results; however, because of its simplicity, the trapezoidal equation is commonly used. Since the trapezoidal equation introduces an error of about 2 percent where the ratio of successive areas is 0.5, a common convention is used to employ both equations. Wherever the ratio of the areas within any two successive isochore lines is smaller than 0.5, the pyramidal equation is applied. Wherever the ratio of the areas within any two successive isochore lines is larger than 0.5, the trapezoidal equation is used. Computer programs, for calculating reservoir volumes from net pay maps, are capable of combining the pyramidal and trapezoidal equations in the manner described. However, the programs may vary in the cutoff ratio that is used, so that ratio for a given program should be determined by the user.

Figure 14-40 and Table 14-1 outline the volume determination using the horizontal slice method. Take a few minutes and review this example to obtain a good understanding of the procedure.

Vertical Slice Method

VERTICAL SLICE

The vertical slice method sums the volumes of *vertical* slices through the depicted reservoir volume (Fig. 14-41). The method is sometimes referred to as the donut method because the individual areas used to determine the reservoir volume fall between successive contour lines and commonly appear to be donut-shaped. Many people consider this method to be less confusing than the horizontal slice method, particularly if isochore maps have a number of thick and thin areas. The equation for the vertical slice method is

$$\text{Volume} = h(A_0 - A_1) + h(A_1 - A_2) + \ldots h(A_{x-1} - A_n) + h_{avg}(A_x) \qquad (14\text{-}3)$$

where

h = Average thickness between successive contour lines
A_0 = Zero contour line
A_i = Next higher value, or next successive, contour line
A_n = Highest value contour line
h_{avg} = Average thickness within A_n

Figure 14-41 and Table 14-2 illustrate the procedure for volume determinations using the vertical slice method. The reservoir used for this example is the same one used for the horizontal slice method (Fig. 14-40), so the results can be compared. The difference in calculated volume between the horizontal and vertical slice methods, for the example in Figs. 14-40 and 14-41, is less than 1 percent.

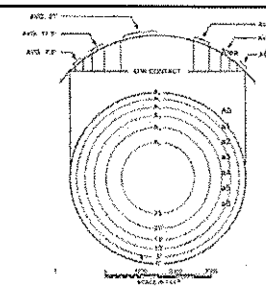


Figure 14-41 Cross section and net pay isopach of an idealized reservoir. [illegible] (Craft and Hawkins 1959; [illegible])

		Hsum	Havg	V
450		0		
375	0.833333	5		
303	0.808	5		
231	0.762376	5	15	12.5	900
154	0.666667	5	20	17.5	1347.5
74	0.480519	5	25	22.5	1800
0	0	4	29	27	1998
					6773

Table 14-2

Area	Planimeter Area Sq. In.	Area Acres	Difference in Areas $A_{n-1} - A_n$	Average Thickness Feet	V Ac. Ft.
A_0	12.54	450	–	–	–
A_1	10.24	375	75	2.5	[illegible]
A_2	[illegible]	303	72	7.5	[illegible]
A_3	[illegible]	231	72	12.5	900
A_4	[illegible]	154	77	17.5	[illegible]
A_5	[illegible]	74	[illegible]	22.5	[illegible]
A_6	[illegible]	0	74	[illegible]	[illegible]
				Total ac. ft.	[illegible]

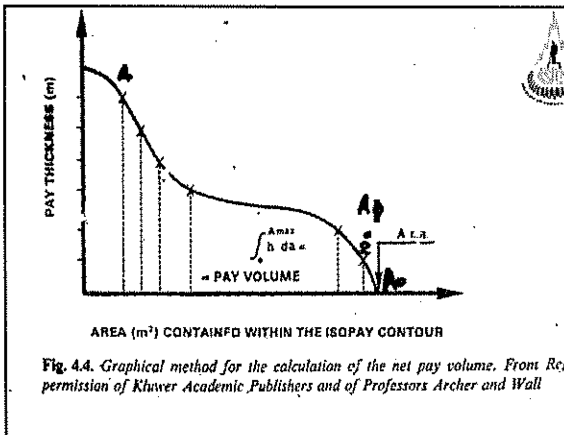
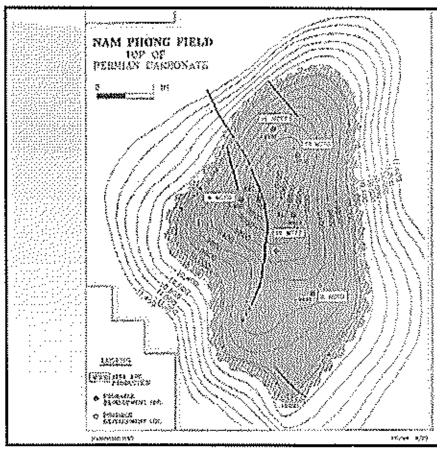


Fig. 4.4. *Graphical method for the calculation of the net pay volume. From Ref permission of Kluwer Academic Publishers and of Professors Archer and Wall*



eral reservoir engineering may be helpful, and it is outlined here.

Using the letter symbols G and N, initial in-place volumes of oil and gas can be determ by the following equations.

$$G = (43{,}560)(\phi)(1 - S_{wi})(B_{gi})(\text{reservoir volume, in acre-feet})$$

$$= Ah\text{ø}(1\text{-}S_{wi})B_{gi}$$

and

$$N = \frac{(7758)(\phi)(1 - S_{wi})(B_{gi})(\text{reservoir volume, in acre-feet})}{B_{oi}}$$

where

$$= Ah\text{ø}(1\text{-}S_{wi})B_o/5.615$$

area square feet

thickness feet

G = original gas-in-place, in cu ft
N = original oil-in-place, in barrels
ϕ = effective porosity, fraction
S_{wi} = interstitial water saturation, fraction
B = formation volume factor, dimensionless
43,560 = cu ft per acre-foot
7758 = barrels per acre-foot
subscript o = oil-bearing zone
subscript g = gas-bearing zone
B_{gi} = standard cu ft/reservoir cu ft

Gas Reservoirs. Equation (14-4) is used to estimate original gas-in-place. There are several unknown factors in the equation that must be determined. The formation volume factor (FVF) is defined as the relationship of gas volumes from surface conditions to reservoir conditions. For gas reservoirs, B_{gi} is expressed in standard cubic feet per cubic foot, SCF/cu ft. The porosity is expressed as a fraction of the bulk volume, and the interstitial water (S_w) is a fraction of the pore volume.

To determine the unit recovery for a gas reservoir, the final reserve volume per acre-foot is determined based on the reservoir drive mechanism. This fractional recovery, or *recovery factor,* represents the difference between the initial unit-in-place gas and the final, or abandonment, unit-in-place gas.

$$\text{Recovery Factor } (RF) = \frac{100(G - Ga)}{G}$$

or

$$RF = \frac{100(B_{gi} - B_{ga})}{B_{gi}} \text{ percent} \qquad (14\text{-}6)$$

where

B_{gi} = formation volume factor at initial conditions
B_{ga} = formation volume factor at abandonment conditions

This recovery factor is indicative of depletion drive reservoirs, where interstitial water saturation remains unchanged and, conversely, gas saturation remains constant. The other end of the spectrum with regard to drive mechanisms is a strong water drive, where produced gas is being replaced by encroaching water (there is no appreciable pressure loss and $B_{gi} = B_{ga}$). The recovery factor for a water-drive gas reservoir, which is representative of the change in gas and water saturations in the reservoir due to production, is shown in the following equation.

$$RF = \frac{100(1 - S_{wi} - S_{gr})}{(1 - S_{wi})} \text{ percent} \qquad (14\text{-}7)$$

where

S_{wi} = interstitial water saturation, friction
S_{gr} = residual gas saturation, fraction

Oil Reservoirs. Oil reservoirs are often more difficult to analyze for a number of reasons, including the presence in some reservoirs of both oil and gas. If an oil reservoir is found without free gas, the oil is said to be *undersaturated.* An oil reservoir with a free gas cap is indicative of a saturated oil reservoir.

Equation (14-5) is used to volumetrically determine original oil-in-place. The variables in Eq. (14-5) are very similar to those discussed for Eq. (14-4). If we consider an undersaturated oil reservoir under a strong water drive, the recovery factor is based on the following equation

$$RF = \frac{100(1 - S_{wi} - S_{or})}{(1 - S_{wi})} \text{ percent} \qquad (14\text{-}8)$$

where

S_{or} = residual oil saturation, decimal

Where there is an initial gas cap, the oil is saturated. In such cases, the reservoir can be produced under drive mechanisms other than water drive. These include dissolved gas, gas cap, or a combination drive. The opposite end of the recovery factor spectrum from a water drive reservoir is that of a dissolved gas drive reservoir.

$$RF = \frac{(1 - S_{wi} - S_{ga})(B_{oi})}{(1 - S_{wi})(B_{oa})} \text{ percent} \qquad (14\text{-}9)$$

where

S_{wi} = interstitial water saturation, fraction
S_{ga} = gas saturation at abandonment, fraction
B_{oi} = initial formation volume factor
B_{oa} = formation volume factor at abandonment
RF = recovery factor, percent

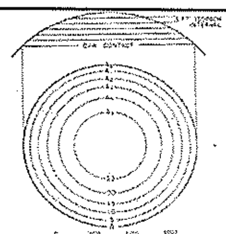


Fig. 3.1. Cross section and isopachous map of an idealized reservoir.

Solution.

Productive Area	Planimeter Area* sq in.	Area acres*	Ratio of Areas	Interval h, feet	Equation	ΔV ac-ft
A_0	19.64	450				
A_1	16.34	375	0.83	5	Trap.	2063
A_2	13.34	303	0.81	5	Trap.	1695
A_3	10.05	231	0.76	5	Trap.	1335
A_4	6.69	154	0.67	5	Trap.	965†
A_5	3.22	74	0.48	5	Pyr.	558
A_6	0.00	0	0.00	4	Pyr.	99
						6715 ac-ft

*For a map scale of 1 in. = 1000 ft; 1 sq in. = 22.96 ac

$^{\dagger}\Delta V = \frac{5}{2}(154 + 74) = 570$ ac-ft

$\Delta V = \frac{5}{3}(154 + 74 + \sqrt{154 \times 74}) = 558$ ac-ft

$\Delta V = \frac{4}{3}(74) = 99$ ac-ft

HW NO 1 DO Chapter1 problem; 1 and 2 Due Date; Friday 18 January 2013

1. In a sandstone reservoir you have calculated the following values from well logs. Each is an average of a five foot thick zone. What is the permeability of each zone, where is the oil water contact and what would you produce from each zone. Assuming this well drains 40 acres calculate the oil in-place in reservoir barrels.

Porosity%	Water Saturation%
25	12
26	15
25	22
23	22
28	30
26	50
28	100

2. In a carbonate reservoir you have the following water saturations and porosities. What fluids would you expect to produce from each zone and where are the producing hydrocarbon-water contacts?

Porosity%	Water Saturation%	Thickness (ft)
2	100	20
5	30	3
9	40	4
1	100	3
12	31	10
17	45	5
2	100	2
4	95	6
8	25	4
7	20	11
3	85	[illegible]

If the reservoir hydrocarbon is gas, what are the cubic feet of gas in-place at reservoir temperature and pressure. Assume a drainage area of 160 acres.

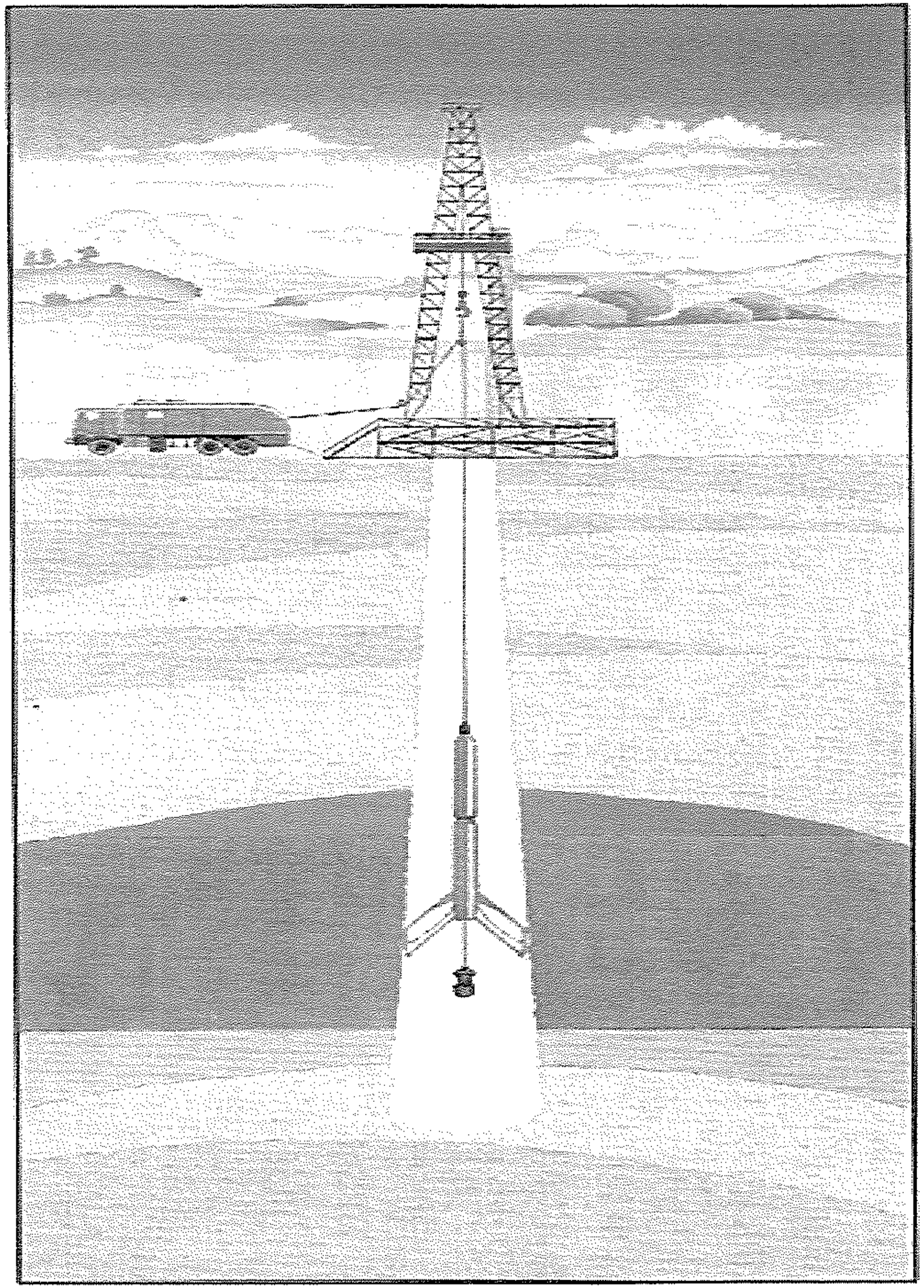


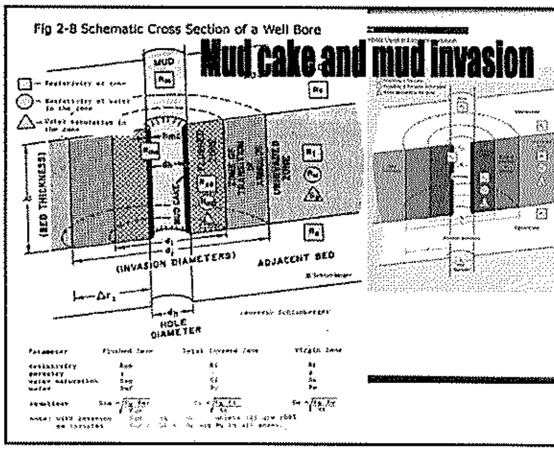
Fig. 1-2—Wireline logging operation.

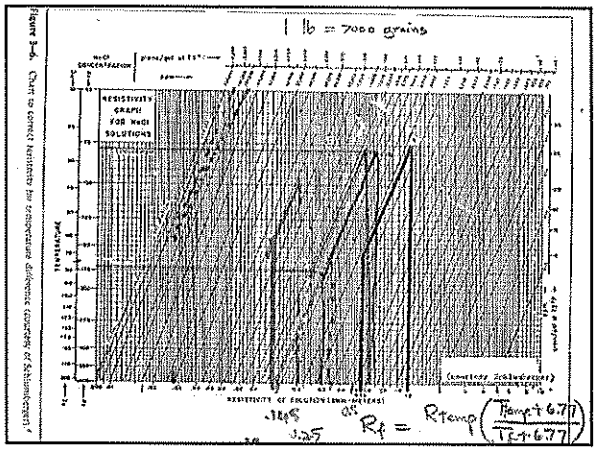
WELLLOGGING

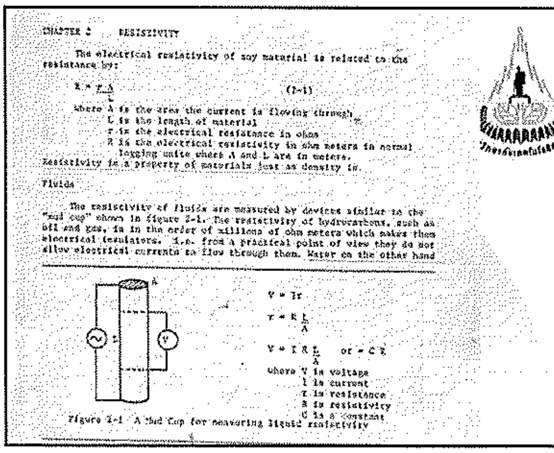
มหาวิทยาลัยเทคโนโลยีสุรนารี

CHAPTER2

CHAPTER3







CHAPTER 2 RESISTIVITY

The electrical resistivity of any material is related to the resistance by:

$R = \frac{r A}{L}$ (2-1)

where A is the area the current is flowing through,
L is the length of material,
r is the electrical resistance in ohms,
R is the electrical resistivity in ohm meters in normal logging units where A and L are in meters.

Resistivity is a property of materials just as density is.

Fluids

The resistivity of fluids are measured by devices similar to the "mud cup" shown in figure 2-1. The resistivity of hydrocarbons, such as oil and gas, is in the order of millions of ohm meters which makes them electrical insulators, i.e. from a practical point of view they do not allow electrical currents to flow through them. Water on the other hand

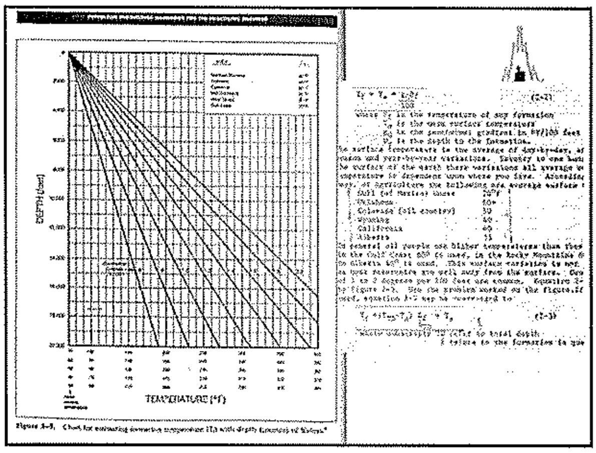
$V = Ir$

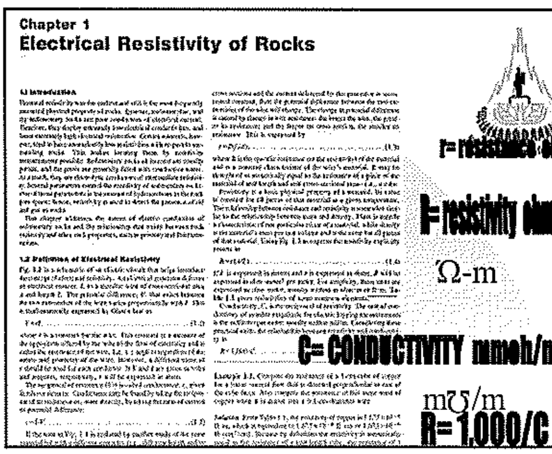
$r = R\frac{L}{A}$

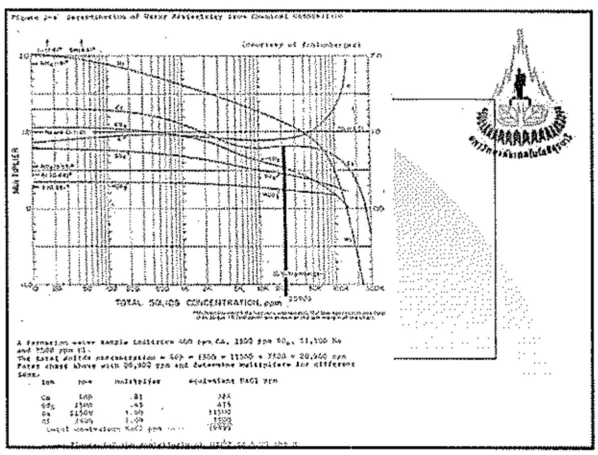
$V = I R \frac{L}{A}$ or $= C R$

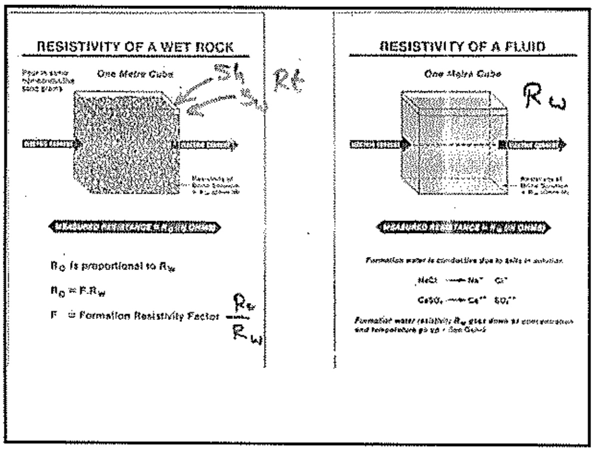
where V is voltage
I is current
r is resistance
R is resistivity
C is a constant

Figure 2-1 A Mud Cup for measuring liquid resistivity









RESISTIVITY OF A WET ROCK
One Metre Cube
Sh
Rt
R_o is proportional to R_w
$R_o = F.R_w$
F = Formation Resistivity Factor $\frac{R_o}{R_w}$
RESISTIVITY OF A FLUID
One Metre Cube
R_w
Formation water is conductive due to salts in solution
NaCl → Na⁺ Cl⁻

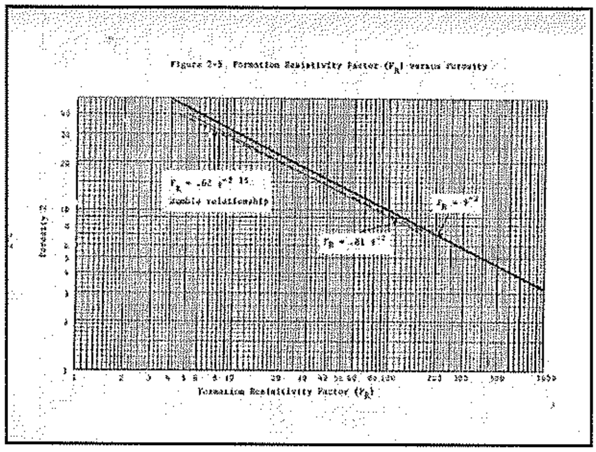
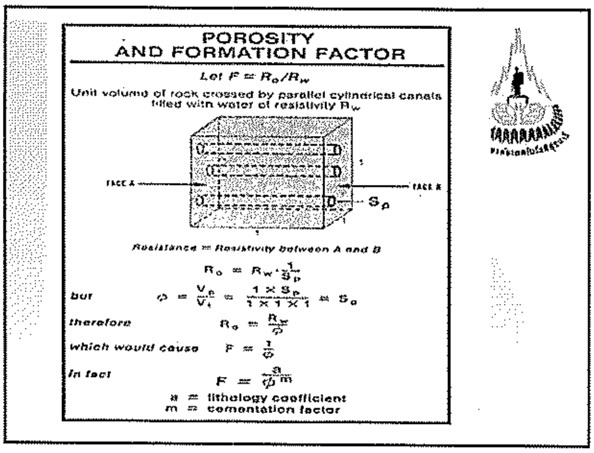
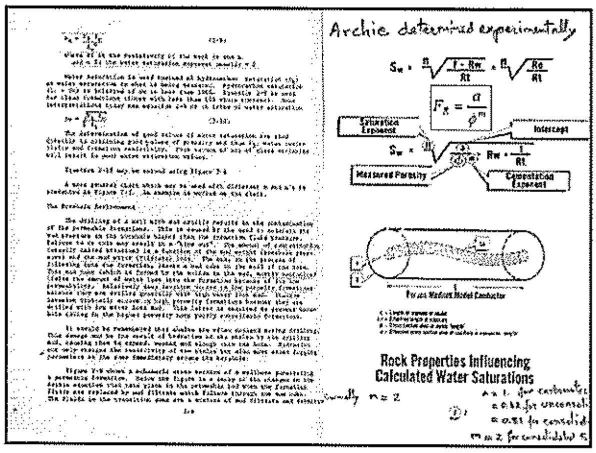


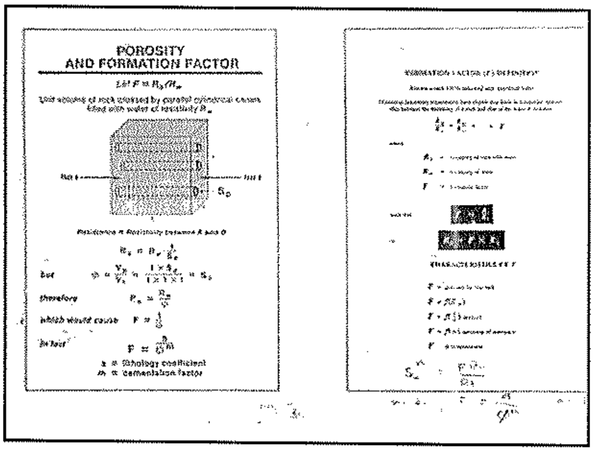
Figure 2-5. Formation Resistivity Factor (F_R) versus Porosity
Humble relationship
Formation Resistivity Factor (F_R)



POROSITY
AND FORMATION FACTOR
Let $F = R_o/R_w$
Unit volume of rock crossed by parallel cylindrical canals filled with water of resistivity R_w
FACE A
FACE B
S_p
Resistance = Resistivity between A and B
$R_o = R_w \cdot \frac{1}{S_p}$
but $\phi = \frac{V_p}{V_t} = \frac{1 \times S_p}{1 \times 1 \times 1} = S_p$
therefore $R_o = \frac{R_w}{\phi}$
which would cause $F = \frac{1}{\phi}$
In fact $F = \frac{a}{\phi^m}$
a = lithology coefficient
m = cementation factor



Archie determined experimentally
$S_w = \sqrt[n]{\frac{F \cdot R_w}{R_t}} = \sqrt[n]{\frac{R_o}{R_t}}$
$F_R = \frac{a}{\phi^m}$
Saturation Exponent
Intercept
Measured Porosity
Cementation Exponent
Rock Properties Influencing
Calculated Water Saturations
usually n = 2
a = 1 for carbonates
= 0.62 for unconsol.
= 0.81 for consolid.
m = 2 for consolidated S



POROSITY
AND FORMATION FACTOR
Let $F = R_o/R_w$
which would cause
In fact
a = lithology coefficient
m = cementation factor
CHARACTERISTICS OF F

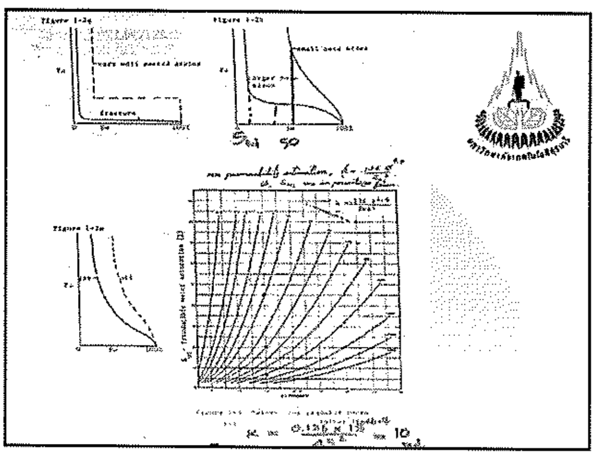
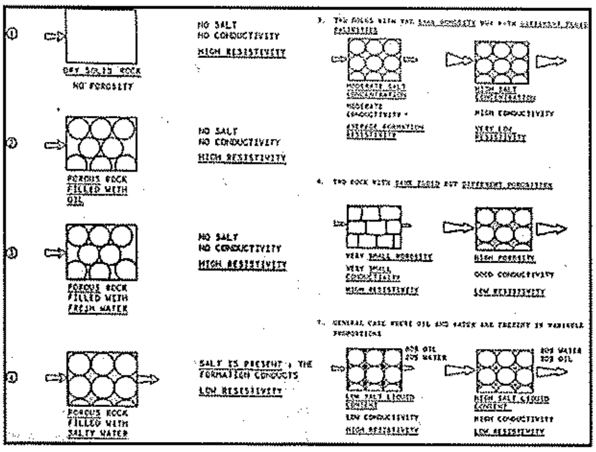
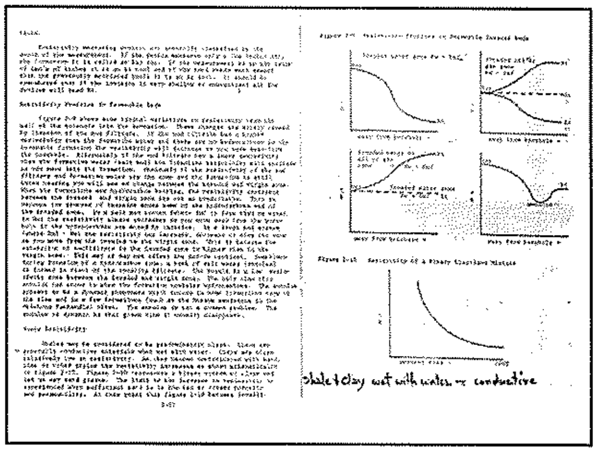
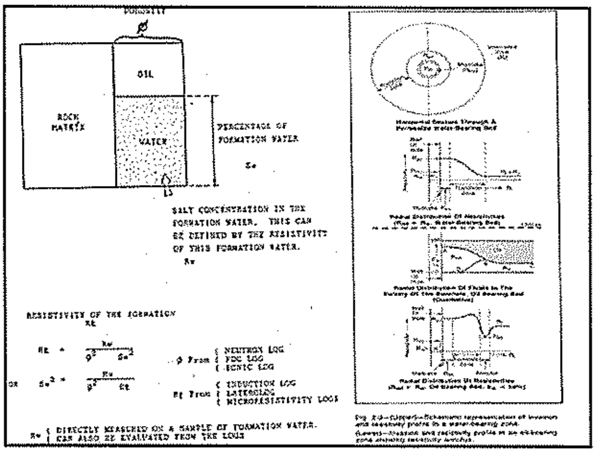
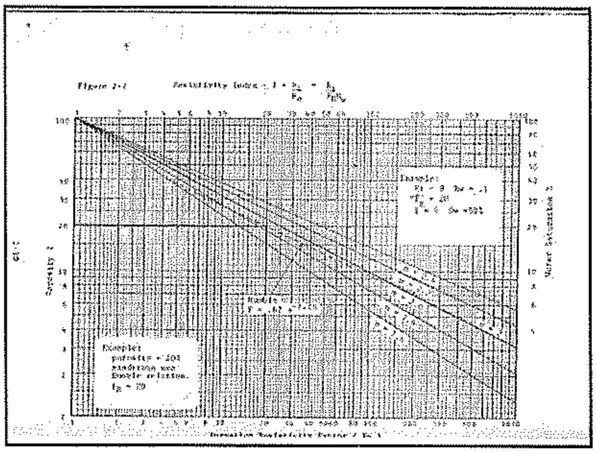


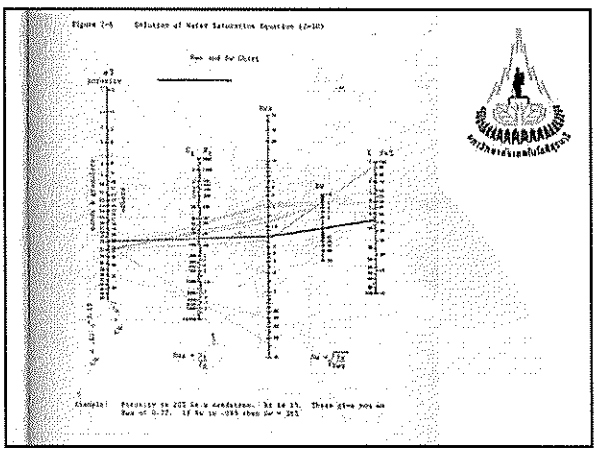
Figure 1-2a
Figure 1-2b
fracture

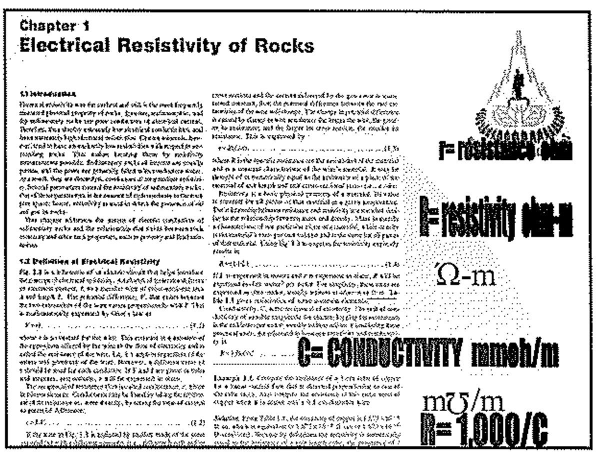

NO SALT
NO CONDUCTIVITY
HIGH RESISTIVITY
DRY SOLID ROCK
NO POROSITY
POROUS ROCK FILLED WITH OIL
POROUS ROCK FILLED WITH FRESH WATER
SALT IS PRESENT ; THE FORMATION CONDUCTS
LOW RESISTIVITY
POROUS ROCK FILLED WITH SALTY WATER
VERY SMALL POROSITY
HIGH POROSITY
GOOD CONDUCTIVITY
LOW RESISTIVITY
HIGH CONDUCTIVITY
LOW CONDUCTIVITY


Shale + clay wet with water → conductive

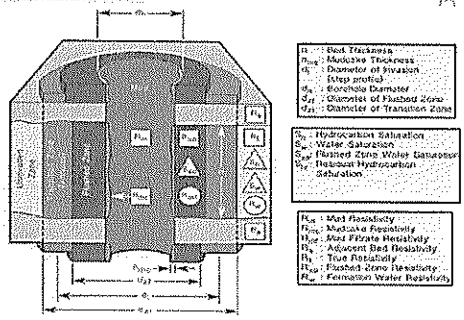

ROCK MATRIX
OIL
WATER
PERCENTAGE OF FORMATION WATER
RESISTIVITY OF THE FORMATION






Chapter 1
Electrical Resistivity of Rocks
r= resistance ohm
R= resistivity ohm-m
Ω-m
C= CONDUCTIVITY mmoh/m
m℧/m
R= 1,000/C

Some definitions

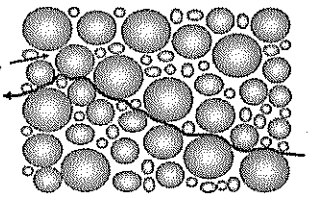


Resistivity (r)

Assume a 100% water-bearing formation...
Rock is an insulator

R_w

$R_o > R_w$



Where Ro is the wet formation resistivity

WATER SATURATION EQUATION

$$\boxed{S_w = c\sqrt{R_w / R_t} / \phi}$$

Where c = 1.0 for carbonates and 0.90 for sands.

This is the basic equation of log interpretation. The whole well-logging industry is built upon this equation.

The equation shows that hydrocarbons in place can be evaluated if there are sufficient logs to give interstitial water resistivity (R_w), formation resistivity (R_t), and Porosity (ϕ). In practice Rw is obtained either from applying the equation in a nearby water sand ($S_w = 1$) or from the SP log or from catalogs or water sample measurements; and ϕ is obtained from porosity logs (Density, Neutron, or Sonic). R_t is obtained from deep resistivity readings (Induction or Laterolog)

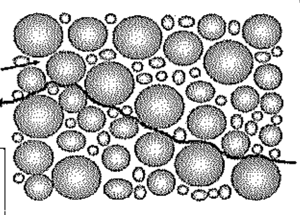
Resistivity (r)

Assume a 100% water-bearing formation...
Rock is an insulator

$$F_r = \frac{R_o}{R_w}$$

R_w

$R_o > R_w$



Where
Ro is the wet formation resistivity
Fr is the formation resistivity factor

Resistivity (r)

Assume a 100% water
Water (salinity) is a conductor

Current travels along the path of least resistance

R_w

$R_o = R_w$

Where Ro is the wet formation resistivity

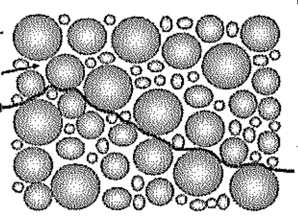
Resistivity (r)

$R_o = f(R_w$, amount of water present) ...
... amount of water present = porosity

Increase porosity...
...decrease Ro

R_w

$$R_o \approx \frac{R_w}{\phi}$$



$$F_r \approx \frac{1}{\Phi}$$

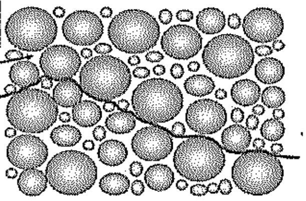
The length of the current path increases as the tortuous of the pore system increases

Resistivity (r)

Tortuosity factor (a) and cementation factor (m)

$$F_r = \frac{R_o}{R_w}$$

$$F_r = \frac{a}{\Phi^m}$$



Calculate Rwa based on Archie equations

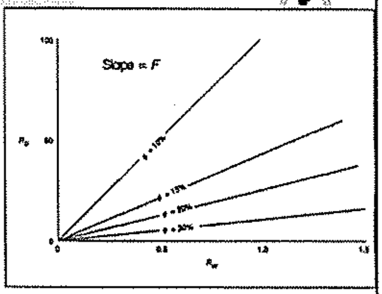
$$F_r = \frac{R_o}{R_w} \qquad F_r = \frac{a}{\Phi^m}$$

$$R_w = \frac{R_o}{F} = \left(\frac{R_o}{a}\right)\phi^m$$

Hence in a 100% water bearing interval we can calculate Rw if we know porosity and the measured resistivity. Assuming we know the constants a and m

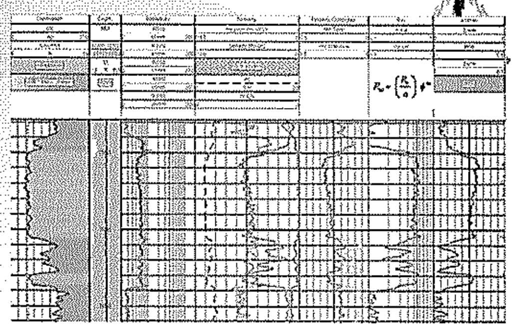
Archie's Experiments

Archie method to derive his conclusion was quite simple. He took a number of cores of different porosity and saturated each one with a variety of brine. He could then measure, at each brine salinity, the resistivity of the water, Rw and the resistivity of the 100% water saturated rock system, Ro. When he plotted the results he saw a series of straight lines with slope F as shown here



$$F_r = \frac{R_o}{R_w}$$

Calculate Rwa based on Archie equations



Archie's Experiments

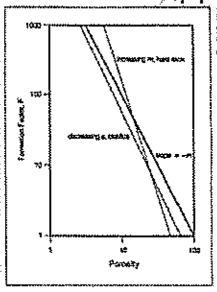
Archie found that laboratory measurements of F could also be related to the porosity of the rock by an equation of the form,

$$F_r = \frac{a}{\Phi^m}$$

Where a and m are experimentally determined constants, a is usually close to 1 and m is usually close to 2

$$\text{Log}(F) = \text{Log}(a) - m*\text{Log}(Phi)$$

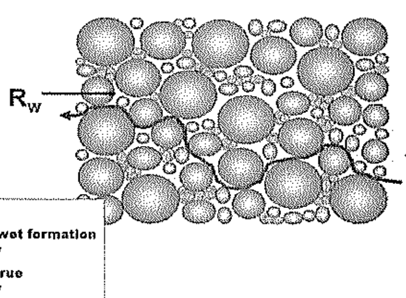
Log-Log plot of F vs Porosity



Resistivity (r)

Now add oil to that formation...
Oil is an insulator

$R_T > R_0$



Where

Ro is the wet formation resistivity

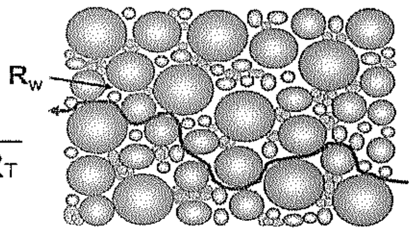
Rt is the true resistivity

Resistivity (r)

$R_T = f(R_w$, amount of water, amount of oil)

$$S_w = \frac{R_0}{R_T}$$

$$S_w \approx \frac{R_w}{\phi * R_T}$$



- a
  - Related to the rock conductivity
  - Usually 1
- m
  - Cementation or Porosity exponent
  - Usually 2
    - Lower in rocks containing hydraulically connected pores (fractures)
    - Higher in rocks containing hydraulically isolated pores (vugs)
- n
  - Saturation exponent
  - Usually 2
  - Varies by degree of wetability - Oil Wet = high "n"

The Archie Equation

$$S_w = \sqrt[n]{\frac{a}{\Phi^m} \times \frac{R_w}{R_t}}$$

Tortuosity Factor and Cementation Exponent

Formation Water

Saturation Exponent

Porosity

Uninvaded Zone Resistivity

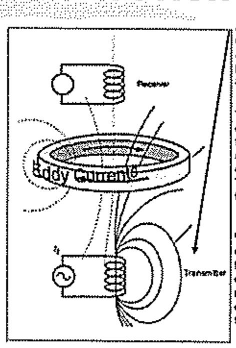
INDUCTION LOGGING THEORY

Induction tools measure formation conductivity by inducing a current flow within the formation

Archie Equation

		Lithology assumptions	Core Analysis	Logs
n	Saturation Exponent	YES	YES	
a	Tortuosity Factor	YES	YES	
Φ	Porosity		YES	Density, Neutron, Acoustic, NMR
m	Cementation Exponent	YES	YES	
R_t	Formation Resistivity			Induction, Laterolog (deep)

INDUCTION PRINCIPLES

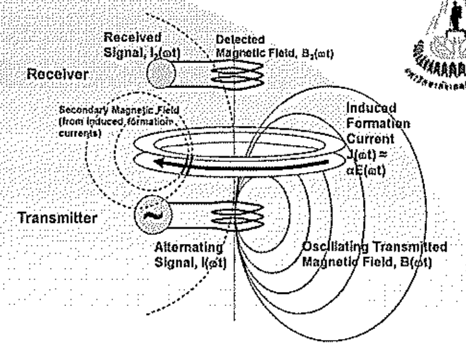


A transmitter coil, with an alternating current passing through it, sets up an alternating magnetic field. "Faraday's law" predicts this time-varying field will establish an emf in the formation.

The emf causes eddy currents to flow in circular paths around the tool (coaxial with the borehole) in areas of formation known as "ground loops." The eddy currents are 90° out of phase with the transmitter currents. Their magnitude depends on the surrounding formation's conductivity.

"Ampere's law" predicts that these eddy currents will produce their own magnetic fields. These fields cut through the receiver coil and induce an alternating voltage at the receiver that is proportional to the strength of the secondary magnetic field and therefore related to formation conductivity.

Induction Principles



THEORY, MEASUREMENT, AND INTERPRETATION OF WELL LOGS

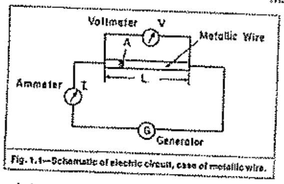


Fig. 1.1—Schematic of electric circuit, case of metallic wire.

TABLE 1.1—ELECTRICAL RESISTIVITY OF SOME COMMON ELEMENTS AT 20°C [68°F] (after Ref. 1)

Element	R ($\Omega \cdot m \times 10^{-8}$)
Aluminum	2.6548
Copper	1.6730
Gold	2.3500
Iron	9.7100
Lead	20.6430
Nickel	6.8400
Silver	1.5900
Zinc	5.9160

cm³ of copper is 1.673×10^{-6} Ω. This result can also be obtained analytically from Eq. 1.3:*

$$r = R(L/A)$$

$$= 1.673\times10^{-8}\ \Omega\cdot m(10^{-2} m/10^{-4} m^2) = 1.673\times10^{-6}\ \Omega.$$

When drawn into a wire, the mass of copper will yield a conductor L cm long. Because the diameter, d, and the volume of the wire are 0.1 cm and 1 cm³, respectively,

$$1\ cm^3 = AL = (\pi d^2/4)L,$$

$$\text{so } L = \frac{1}{[\pi(0.1)^2/4]} = 127.3\ cm = 1.273\ m.$$

From Eq. 1.3,

$$r = 1.673\times10^{-8}\ \Omega\cdot m\frac{1.273\ m}{[(\pi(0.001)^2 m^2)/4]}$$

$$= 0.027\ \Omega.$$

in the water, it becomes possible to pass a current through the core plug now saturated with the brine. The conduction is realized through the salt solution, usually referred to as electrolyte.

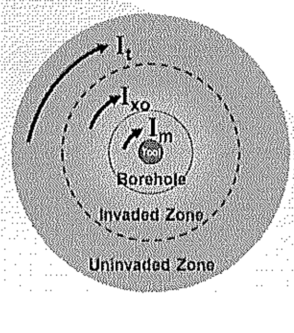
The salt molecules when dissolved in water dissociate into particles called ions. Ions are atoms and molecules electrically charged as a result of electron excess or deficiency. For NaCl, the sodium atoms dissociate as positively charged ions (cations) and the chlorine atoms dissociate as negatively charged ions (anions):

$$NaCl \rightarrow Na^{+} + Cl^{-}. \quad (1.6)$$

When an electric field is established across the core plug, the ions drift through the water, the positive ions toward the negative electrode and the negative ions toward the positive electrode. The electric charges—i.e., electric current—are carried within the rock sample by ions and in the external circuit by electrons. The conduction within the rock is electrolytic.

1.4 Formation Resistivity Factor

When the rock sample in Fig. 1.2 is saturated with salt water whose resistivity is R_w, a current will circulate through the electric ...



= 0.027 Ω.

1.3 Nature of Electrical Resistivity of Reservoir Rocks

Reservoir rocks are commonly porous and permeable sedimentary rocks. They include three major rock types: (1) sandstones, which are consolidated fragments of mainly quartz minerals, SiO_2; (2) limestone, $CaCO_3$, which is formed by chemical precipitation or accumulation of organic calcite remains; and (3) dolomite, $CaMg(CO_3)_2$, which is formed mainly by chemical alteration of limestone. Most porous sedimentary rocks contain water in their pores. The water usually contains some dissolved salt. The degree of salinity varies greatly. In addition to water, reservoir rocks may also contain oil and/or natural gas.

The nature of the resistivity of a reservoir rock can be explained by replacing the wire in the electric circuit in Fig. 1.1 with a dry and clean core plug of one of the above three rocks. A core plug is usually a cylindrical sample used in core analysis. Solvents are used to clean the sample of all residual fluids. The result is a dry and clean core plug that contains only air in its pore space. The core plug is fitted with electrodes that cover the entire area of the two opposite plane faces (Fig. 1.2). This arrangement will ensure linear current flow.

With the clean and dry core plug in place of the metallic wire, no significant current will pass through the circuit because the rock matrix and the air saturating its pore space are both poor electrical conductors, or insulators. However, reservoir rocks in situ are almost always conductors. Because oil and gas are also insulators, the electrical conduction in reservoir rocks results from the presence of water. Saturating the core plug of Fig. 1.2 with pure water will not result in any significant change from the previous case where the pore fluid is air because pure water is also an extremely poor conductor. If a salt, such as sodium chloride (NaCl), is dissolved

*In examples in this book, computed values are not always stated to their full number of significant digits. ...

1.4 Formation Resistivity Factor

When the rock sample in Fig. 1.2 is saturated with salt water whose resistivity is R_w, a current will circulate through the electric circuit and a corresponding potential drop is observed across the sample. The resistance of the rock sample can be determined with Ohm's law. If in turn this resistance value is substituted along with values of A and L in Eq. 1.4, the rock's overall resistivity, R_o can be calculated. When the rock is fully saturated with water, the resistivity is R_o. Because the only conducting medium in the rock sample is the salt water, it is possible to replace the core sample by a volume of water of the same resistivity and still obtain the same resistance between the two electrodes (Fig. 1.3). Ions moving through a porous rock follow a tortuous path, so the length of the equivalent water volume, L_e, is greater than the actual length, L. If the porosity of the rock is ϕ, then the volume of the water in the rock sample is ϕAL. This volume should also be that of the equivalent water body to maintain the same salinity. The cross-sectional area of the equivalent water volume, A_e, has to be $\phi AL/L_e$. Using Eq. 1.3 to express the resistance of the core plug fully saturated with water, r_o, and the resistance of the equivalent water volume, r_{we}, results in

$$r_o = R_o(L/A) \quad (1.7)$$

$$\text{and } r_{we} = R_w\frac{L_e}{A_e} = R_w\frac{L_e^2}{\phi AL}. \quad (1.8)$$

Because $r_o = r_{we}$,

$$R_o = FR_w \quad (1.9)$$

$$\text{where } F = \left(\frac{L_e}{L}\right)^2\frac{1}{\phi} = \frac{\tau^2}{\phi}. \quad (1.10)$$

F, the formation resistivity factor, depends on the tortuosity, τ, and the porosity, ϕ, of the rock. Tortuosity equals L_e/L.

Because F is a dimensionless quantity that depends only on rock properties, it is an important parameter in electric log interpretation. As will be seen in later chapters, ...

When to Run Induction

	High Water Resistivity, R_w	Medium Water Resistivity, R_w	Low Water Resistivity, R_w
High Mud Resistivity, R_m	Normally OK for induction logs, if porosity > 8% otherwise R_t may be too high (over 250 Ω-m)	Perfect for induction logging	Perfect for induction logging
Medium Mud Resistivity, R_m	Normally OK for induction logs if porosity > 10%	Perfect for induction logging	Perfect for induction logging
Low Mud Resistivity, R_m	Not advised. Borehole signal will often be larger than formation signal		Acceptable for induction logging if porosity > 6% and hole diameter < 10 inches, otherwise borehole signal may overwhelm formation signal

... the relationship between F and ϕ.

Solution. Fig. 1.5 shows the equivalent electric circuit of the rock sample. r_w and r_{ma} are the resistances of the water-filled tube and the rock matrix (frame), respectively. The overall resistance of the rock, r_o, is expressed in terms of r_w and r_{ma}, which are in parallel, as

$$1/r_o = 1/r_w + 1/r_{ma}$$

Because the rock matrix is made of an insulator material ($r_{ma} = \infty$), this equation reduces to

$$r_o \approx r_w.$$

r_o and r_w are expressed by Eq. 1.3 as

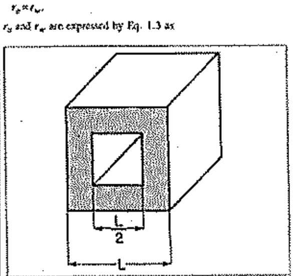


Fig. 1.4—Schematic of the synthetic rock sample of Example 1.2.

$$= \frac{(L/2)^2}{L^2} = \frac{1}{4} = \frac{1}{F}$$

This result is independent of the shape of the tube in the center of the cube. In natural porous media, however, the electric current flows through complex and tortuous channels. The above simple relationship does not hold, but the porosity does remain as the principal parameter controlling the formation resistivity factor.

1.5 Effect of Formation-Water Salinity and Temperature on Rock Resistivity

Because electric charges are carried through sedimentary rocks by ions within the formation water, the parameters that affect formation-water resistivity also affect rock resistivities. In electrolytic conductance, as is the case here, the conductivity of a solution depends on (1) the number of ions present in the solution, called concentration or, for formation waters, salinity; (2) the velocity at which the ions move through the solution; and (3) the charge of the ions, which is determined by the type of salt in solution.

Most chemical analyses of the salt composition of a conductive solution express ionic concentration as a weight of salt per unit ...

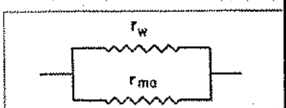


Fig. 1.5—Equivalent electric circuit of the rock sample of Example 1.2

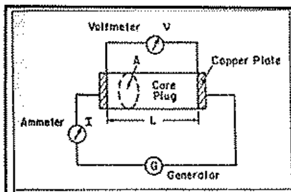


Fig. 1.2—Schematic of electric circuit, case of core plug.

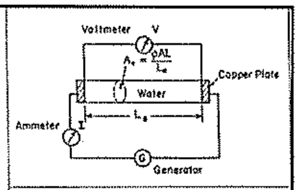


Fig. 1.3—Schematic of electric circuit, case of tube of water.

1. To determine R_o when F and R_w are known. R_o can then be compared with the true resistivity of the formation, R_t, to detect the presence of hydrocarbons.
2. To determine F when R_o and R_w are known. F can then be used to estimate the porosity of the formation.
3. To determine R_w when F and R_o are known. R_w can then be used in other petrophysical models or to determine the salinity of formation water.

Example 1.2. Consider a synthetic rock sample made of insulator material and shaped as a cube of length L. There is a square tube of dimension $L/2$ through the cube, as shown by Fig. 1.4. Assuming that this square tube is filled with brine of resistivity R_w and that the current will flow perpendicular to the faces with the square holes, calculate the formation resistivity factor of the rock. Also determine the relationship between F and ϕ.

Solution. Fig. 1.5 shows the equivalent electric circuit of the rock sample. r_w and r_{ma} are the resistances of the water-filled tube and the rock matrix (frame), respectively. The overall resistance of the rock, r_o, is expressed in terms of r_w and r_{ma}, which are in parallel, as

$1/r_o = 1/r_w + 1/r_{ma}$

Because the rock matrix is made of an insulator material ($r_{ma} = \infty$), this equation reduces to

$r_o = r_w$.

r_o and r_w are expressed by Eq. 1.3 as

$r_o = R_o(L/L^2) = R_o/L$

and $r_w = R_w \frac{L}{(L/2)^2} = 4\frac{R_w}{L}$.

Then $R_o/L = 4R_w/L$.

By definition,

$F = R_o/R_w = 4$.

The tube of water is not tortuous ($L_e = L$). Eq. 1.10 then reduces to

$F = 1/\phi$.

This simple relation can be checked by calculating the porosity

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

$$= \frac{L(L/2)^2}{L^3} = \frac{1}{4} = \frac{1}{F}.$$

This result is independent of the shape of the tube in the center of the cube. In natural porous media, however, the electric current flows through complex and tortuous channels. The above simple relationship does not hold, but the porosity does remain as the principal parameter controlling the formation resistivity factor.

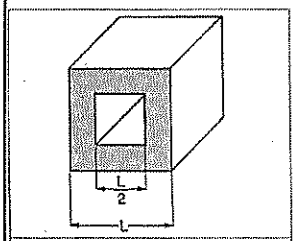


Fig. 1.4—Schematic of the synthetic rock sample of Example 1.2.

1.5 Effect of Formation-Water Salinity and Temperature on Rock Resistivity

Because electric charges are carried through sedimentary rocks by ions within the formation water, the parameters that affect formation-water resistivity also affect rock resistivities. In electrolytic conductance, as is the case here, the conductivity of a solution depends on (1) the number of ions present in the solution, called concentration or, for formation waters, salinity; (2) the velocity at which the ions move through the solution; and (3) the charge of the ions, which is determined by the type of salt in solution.

Most chemical analyses of the salt composition of a conductive solution express ionic concentration as a weight of salt per unit

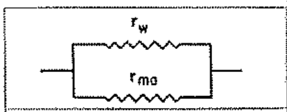
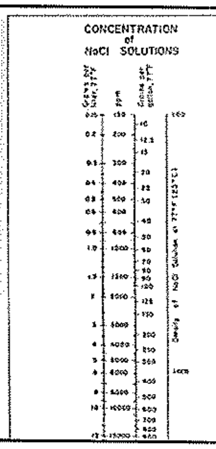


Fig. 1.5—Equivalent electric circuit of the rock sample of Example 1.2



volume of solution in grams per liter or the antiquated grains per gallon. Concentrations expressed on a volumetric basis vary with temperature. When it is desirable to work with values that are temperature-independent, concentrations are expressed on the basis of a weight of salt per unit weight of solution. Formation-water salinities are commonly expressed in parts per million, which is equivalent to milligrams per kilogram. Concentrations given in grams per liter may be converted to parts per thousand by dividing by the density of the solution in grams per cubic centimeter. Of course, the volumetric concentration and the density values must be at the same temperature. The chart in Fig. 1.6 shows the relationship between concentration and density of NaCl solutions at 77°F.

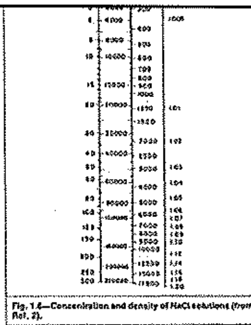


Fig. 1.6—Concentration and density of NaCl solutions (from Ref. 2).

The velocity of ions, usually referred to as mobility, is determined by the opposition or drag force they encounter while moving through the solution. The drag force is controlled mainly by the solvent viscosity and the ion size. Because water viscosity is a steep function of temperature, brine resistivity is strongly dependent on temperature. Fig. 1.7 shows the resistivity of NaCl solutions as a function of concentration and temperature. This nomogram was developed from experimental data.[2]

The effect of temperature on salt-solution resistivity is of considerable importance in quantitative interpretation of electric logs, where it is frequently necessary to correct resistivities measured under surface conditions to temperatures existing at the bottom of or elsewhere in the borehole. Arps[3] developed an empirical approximation for this conversion that provides results within the range of accuracy of the data involved. This approximation equation states that

$$R_2 = R_1 \frac{T_1 + 6.77}{T_2 + 6.77}, \qquad (1.11)$$

where R_1, R_2 = resistivities of NaCl solutions at temperatures of T_1 and T_2, °F, respectively.

Example 1.3. An NaCl solution has an electric conductivity of 20,000 mU/m at 77°F. Determine (1) the solution resistivity at 77°F, (2) the solution salinity in ppm and in g/L, and (3) the solution resistivity at 200°F.

Solution.

1. From Eq. 1.5,

$$R_w = \frac{1{,}000}{20{,}000} = 0.05\ \Omega\cdot\text{m at } 77°\text{F}.$$

2. In the nomograph of Fig. 1.7, the line joining the two points that represent 77°F and 0.05 Ω·m intersects the salinity scale at about 170,000 ppm. From the nomograph of Fig. 1.6, this value corresponds to 190 g/L at 77°F.

3. From the nomograph of Fig. 1.7, the line that joins the two points representing 200°F and 170,000 ppm intersects the resistivity scale at a value of 0.02 Ω·m. This value can also be calculated from Eq. 1.11:

$$R_w = 0.05\frac{77 + 6.77}{200 + 6.77} = 0.02\ \Omega\cdot\text{m at } 200°\text{F}.$$

The conductivity of each pure-salt solution normally found in formation waters varies uniquely with concentration, as illustrated by Fig. 1.8. As can be seen, the conductivity is different for different salts. For some salts, such as potassium chloride (KCl), the conductivity increases as concentration increases. For some other salts, such as calcium chloride ($CaCl_2$), conductivity increases at first as concentration increases then declines at higher concentrations. In more concentrated solutions, compounds of polyvalent ions show incomplete dissociation. For example, $CaCl_2$ dissociates to $CaCl^{+} + Cl^{-}$ instead of $Ca^{++} + 2Cl^{-}$. At higher concentration levels, additional salt is slightly dissociated, tying up some of the free water and causing an increase in viscosity and hence a decline in conductivity.

In solutions containing more than one salt, the contribution of one salt to the total conductivity depends on (1) the total solids concentration in the mixed solution, (2) the fractional concentration of the salt, and (3) the conductivity of this same salt at the total solids concentration. The analytical or experimental determination of a mixed-salt solution as a function of all solutes present is complex and impractical. With an accuracy sufficient for practical purposes, the conductivity of a solution of N salts is given by[4]

$$C_t = \frac{1}{n_t}\sum_{i=1}^{N} n_i C_i, \qquad (1.12)$$

where C_t = conductivity of the solution, U/m; n_t = total-dissolved-solids (TDS) concentration, ppm; n_i = concentration of the ith salt, ppm; and C_i = conductivity of the ith salt at concentration TDS, ppm.

Formation waters of moderate to high salinity are predominantly NaCl solutions. Because polyvalent ion concentration is usually low, the conductivity of most formation waters increases with concentration even at high values.

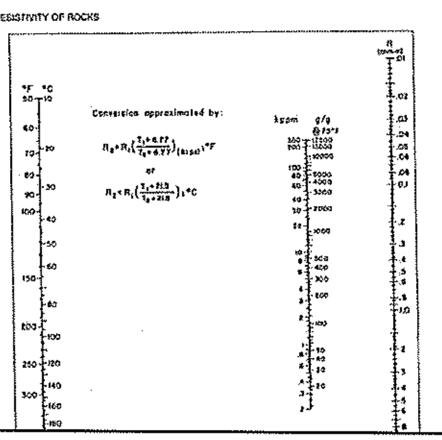


Fig. 1.7—Resistivity nomograph for NaCl solutions (from Ref. 2).

Example 1.4. Estimate the resistivity of a brine that contains 100,000 ppm NaCl, 50,000 ppm $CaCl_2$, and 50,000 ppm $MgCl_2$. What is the concentration of NaCl solution that will have the same resistivity?

Solution. The resistivity of the brine can be estimated with Eq. 1.12. The values of C_i are obtained from Fig. 1.8.

Salt	n_i (ppm)	C_i at n_t (U/m)	n_i/n_t	$(n_i C_i)/n_t$
NaCl	100,000	19.57	0.50	9.785
$CaCl_2$	50,000	17.28	0.25	4.320
$MgCl_2$	50,000	14.02	0.25	3.505
	n_t = 200,000			17.610

$C_t = 17.610$ U/m,

and $R_w = 1/17.610 = 0.057$ Ω·m.

From Fig. 1.8, the concentration of an NaCl solution that displays a conductivity of 17.610 U/m is 166,000 ppm. This concentration is usually referred to as the equivalent NaCl concentration.

In cases where the resistivity of a salt solution has not been measured directly, it can be calculated from chemical analysis of the solution.[4,5] By operating on the ionic concentrations with suitable multipliers, they can be converted to equivalent amounts of NaCl. When the equivalent NaCl concentration of the solution is known, its resistivity can be determined at any temperature with the nomograph of Fig. 1.7. The equivalent NaCl concentration, n_e, of a solution of N salts can be expressed as[5]

$$n_e = \sum_{i=1}^{N} k_i n_i, \qquad (1.13)$$

where k_i = multiplier of the ith ion at TDS concentration, n_t, and n_i = concentration of the ith ion.

Conductivity data of various pure-salt solutions commonly found in formation waters were used in developing these multipliers. Multipliers for the different salts vs. total solid concentration are plotted in Fig. 1.9. Multipliers that do not vary appreciably for low concentrations, less than 10,000 ppm, are shown at the left and top margins of the figure

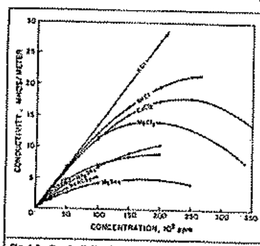


Fig. 1.8—Conductivity of salt solutions at 18°C (after Ref. 4).

Equating a complex mixture to an equivalent NaCl solution implies that the two remain equivalent at all temperatures. However, the dependence of resistivity on temperature is not the same for all salts. It appears that this causes only a minor discrepancy for the range of reservoir brines normally encountered in practical well-log interpretation.[4]

Example 1.6. The average composition of open ocean water is as follows:

Chemical Constituent	Content (ppm)
Calcium (Ca)	419
Magnesium (Mg)	1,304
Sodium (Na)	10,710
Potassium (K)	390
Bicarbonate (HCO_3)	146
Sulfate (SO_4)	2,690
Chloride (Cl)	19,350
Bromide (Br)	70
TDS (salinity)	35,079

Estimate the resistivity of this ocean water at 60°F.

Solution. The equivalent NaCl concentration is first estimated by Eq. 1.33 with multiplier values from Fig. 1.9.

Ion	n_i (ppm)	K_i	$K_i n_i$ (ppm)
Ca	419	0.80	335
Mg	1,304	1.04	1,356
Na	10,710	1	10,710
K	390	0.91	355
HCO_3	146	0.31	45
SO_4	2,690	0.4	1,076
Cl	19,350	1	19,350
Br	70	0.44	31
	n_t=35,079		n_e=33,258

Using the nomograph of Fig. 1.7 yields

R_w=0.24 Ω·m at 60°F.

Note that, because the solution is predominantly NaCl, 30,060 ppm of a total of 35,079 ppm, simply entering the nomograph with a TDS value of 35,079 ppm results in almost the same resistivity value of 0.24 Ω·m. This fact tends to support the common practice of assuming that formation waters are pure NaCl solutions. Such an assumption is particularly useful when formation-water analyses are not available.

1.6 Rock Resistivity/Porosity Relationship

The formation resistivity factor, F, is controlled mainly by porosity and tortuosity, as illustrated by Eq. 1.10. This equation is imprac-

limestone samples with intergranular porosity, a number of samples were dolomitic and/or vugular in structure. A forced fit of the data yielded m=2.04 for a=1.

The following equations are recommended for compact rocks and for low-porosity, nonfractured carbonates, respectively:[2,31]

$$F=1/\phi^{2.2} \approx 2.5 \quad \text{(1.23)}$$

and $$F=1/\phi^{1.87+0.019/\phi}. \quad \text{(1.24)}$$

Eq. 1.24 is called the Shell equation.

All these different generalized equations are represented graphically in Fig. 1.16. In general, each equation yields a different result. Predictions can be misleading unless the most suitable equation is used for each particular application.

Example 1.7. Determine the formation resistivity factor of two U.S. gulf coast sandstone formations with porosities of 15% and 25%, respectively.

Solution. Because there is no mention of core measurements available from these two formations, a generalized equation is used. The most suitable equation should be chosen and the formation factor estimated. The following table lists the different values of F calculated by the different equations suggested for U.S. gulf coast sandstones.

	F	
Equation	ϕ=15%	ϕ=25%
$F=0.62/\phi^{2.15}$ (Humble)	36.6	12.2
$F=1.13/\phi^{1.73}$ (Chevron)	30.1	12.4
$F=1.45/\phi^{1.54}$ (Phillips)	26.9	12.7
$F=1.97/\phi^{1.29}$ (Porter and Carothers)	22.8	11.8

For the formation displaying a relatively high porosity of 25%, the calculated four values of F are close to each other. The maximum deviation between these three values is only about 5%. Any of the four values could be retained for further evaluation of the formation without creating serious interpretation problems.

For the formation that displays a relatively low porosity of 15%, the deviation between the calculated values is as high as 60%. The value of 36.6, calculated from the Humble equation, is the least believable if we take into consideration the number of samples used to derive the different equations. This leaves three values 30.1, 26.9, and 22.8 and the question of which value to choose. The need to answer this question could be avoided by reporting a range of values—i.e., F=22.8 to 30.1. Because F is usually used to calculate other parameters, this option might be impractical. The final choice of a value of F is a matter of personal preference usually dictated by the analyst's experience and bias. The knowledge of how the value of F will be used might be of some help in deciding which F-ϕ relationship is most appropriate.

This decision-making problem is not unique to the calculation of F; it is common throughout the well-log interpretation process.

1.7 Relationship Between Formation Resistivity Factor and Permeability

The actual fluid flow velocity, v_e, within the pores of a medium is greater than the macroscopic velocity, v, implied by q/A, where q is the volumetric flow rate and A is the cross-sectional area of the porous medium. The increased velocity is a result of the increased length of the actual flow path, L_e, compared with the length, L, across the porous medium, and the decreased area of actual flow. The area is decreased by a factor ϕ. Thus, the actual fluid velocity is given by

$$v_e=\frac{v}{\phi}\frac{L_e}{L}=\frac{v}{\phi}\tau. \quad \text{(1.25)}$$

Chemical Constituent	Content (ppm)
Calcium (Ca)	419
Magnesium (Mg)	1,304

1.6 Rock Resistivity/Porosity Relationship

The formation resistivity factor, F, is controlled mainly by porosity and tortuosity, as illustrated by Eq. 1.10. This equation is imprac-

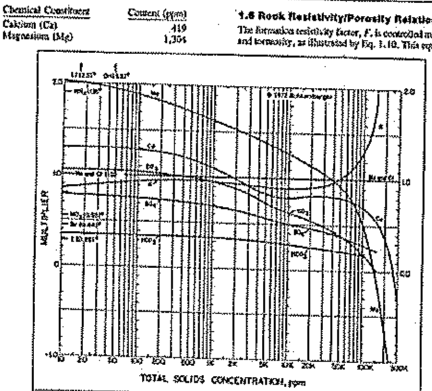


Fig. 1.9—Multipliers of different salts as a function of total dissolved solids concentration (from Ref. 2).

Combining Eq. 1.25 with Darcy's law,

$$v=-(k/\mu)(dp/dL), \quad \text{(1.26)}$$

results in

$$k=\frac{v_e\mu\phi L}{L_e(dp/dL)}=\frac{v_e\mu\phi}{\tau(dp/dL)}, \quad \text{(1.27)}$$

where k=permeability, μ=fluid viscosity, and dp/dL=potential gradient.

It can be observed that, all other parameters remaining invariable,

$$k\propto L/L_e\propto 1/\tau. \quad \text{(1.28)}$$

Hence, permeability decreases as tortuosity increases. From the preceding discussion, it is evident that both the electric conductivity and the permeability of a porous medium are determined by the effective length of the path of flow of ions. The greater this length, the lower the conductivity and permeability. An empirical equation relating these two physical properties of the porous medium can be obtained by combining Eqs. 1.10, 1.14, and 1.28. This relation is of the form[14]

$$F=Ak^{-B} \quad \text{(1.29)}$$

or of the form

$$k=CF^{-D}, \quad \text{(1.30)}$$

where A, B, C, and D are constants for a specific formation.

Various experimental studies corroborate the relationship given by Eq. 1.29. One of the earliest was conducted by Archie,[7] who examined a group of core plugs taken from the producing zones of several U.S. gulf coast wells. He concluded that the formation factor varies, among other properties, with the permeability of the reservoir rock, as shown by Fig. 1.17. In an extensive statistical study, Carothers[12] also observed that a relation exists between permeability and formation resistivity factor. The relationship is

$$k=(4.0\times10^8)/F^{3.43} \quad \text{(1.31)}$$

3. Experimentally determine the R_o of the sample now fully saturated with water of R_w.
4. Compare R_t and R_o values.

If the sample originally contained hydrocarbon, then

$$R_t>R_o \quad \text{(1.33)}$$

or $$R_t/R_o>1. \quad \text{(1.34)}$$

The resistivity ratio is called the resistivity index, I_R:

$$I_R=R_t/R_o. \quad \text{(1.35)}$$

If the sample was originally fully saturated with water, then $R_t=R_o$ and $I_R=1$. Note that the presence of hydrocarbon is indicated by the value of the resistivity index and not by the absolute value of R_t.

What if the measured value of R_o is greater than the measured R_t value? Because this is not physically possible, an error should be suspected. The error, or errors, could have occurred during core preparation, measurement, and/or calculation. The calculations should be checked first. If no calculation errors are discovered, then the core preparation and measurements should be suspected.

The detection of the presence of hydrocarbons in situ follows similar logic. However, the determination of R_o is far more involved.

Because the only conductive medium in a rock sample partially saturated with hydrocarbon is the salt water, it is again possible to replace the sample by a volume of water of the same salinity and still obtain the same resistance, r_t, between the two electrodes of Fig. 1.3. The length and cross-sectional area of the equivalent water volume are L_t' and A_t', respectively. The resistance of the core, r_t, and of the equivalent water volume, r_w, can be expressed as

$$r_t=R_t(L/A) \quad \text{(1.36)}$$

and $$r_w=R_wL_t'/A_t'. \quad \text{(1.37)}$$

But $r_t=r_w$ and $A_t'L_t'=AL\phi S_w$, where S_w=water saturation. Therefore,

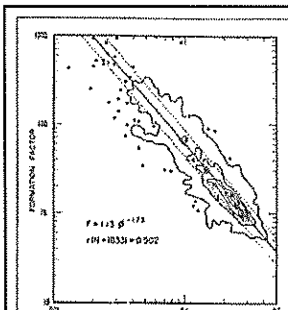


Fig. 1.14—Generalized F-ϕ relationship for sandstone (from Ref. 6).

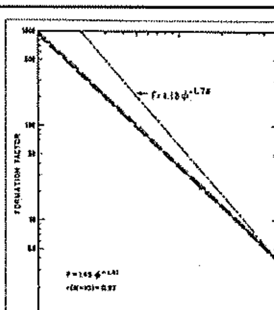


Fig. 1.15—F vs. ϕ for a specific formation compared with generalized F-ϕ relationship (from Ref. 6).

Carothers also reported relationships for specific geologic age, formation, and geographic location.

Chevron Formula. Timur *et al.*[6] gathered an extensive collection of F-ϕ data. The data consist of 1,833 sandstone samples. Analysis of these data resulted in

from well-log data obtained under in-situ conditions. A total of 2,295 F-ϕ data points was gathered from 11 wells from offshore California Pliocene and four wells from offshore Texas-Louisiana Miocene.

The California Pliocene 1,575 data points indicated an F-ϕ relationship of

$$k=(4.0\times10^8)/F^{3.43} \quad \text{(1.31)}$$

for limestones and

$$k=(1.0\times10^8)/F^{4.5} \quad \text{(1.32)}$$

for sandstones. In Eqs. 1.31 and 1.32, permeability is given in millidarcies.

Experience has shown, however, that a generalized equation that relates permeability to porosity or formation resistivity factor yields unsatisfactory results in most cases. The values of the parameters A and B of Eq. 1.29 or C and D of Eq. 1.30 must be determined for each formation from either core measurements or a combination of core measurements and well-log data.[14]

1.8 Relationship Between Rock Resistivity and Fluid Saturation

In the rock sample of Fig. 1.2, let the pore space be partially saturated with water and the remainder of it occupied by oil or gas. Because oil and gas are nonconductors, the resistivity of the rock partially saturated with hydrocarbons, R_t, is higher than the resistivity of the same rock when fully saturated with water, R_o. If the hydrocarbon saturation is increased, resistivity will increase. In true porous media, however, the increase is not directly proportional to the hydrocarbon content. As hydrocarbon replaces water, the resistivity increases slowly at first, for the oil or gas normally fills the center of the pores, leaving enough room for the current to flow. At higher hydrocarbon saturation, when most of the pore space is occupied by nonconductors, the resistivity will increase greatly.

Suppose that it is required to determine experimentally whether a core plug is fully or partially saturated with water of known resistivity R_w. If the sample is partially saturated with water, the remainder of the pore space is occupied by a nonconductor (e.g., oil or gas). The presence of hydrocarbon can be detected electrically by the following procedure.

1. Experimentally determine the R_t of the sample.
2. Remove all fluid(s) from the sample, and then fully saturate it with water of same R_w as before.

fore,

$$R_t=(L_t'/A_t')(R_w/\phi S_w)$$
$$=\tau'^2R_w/\phi S_w. \quad \text{(1.38)}$$

τ', the tortuosity of the current path for a rock partially saturated with water, depends on the manner in which the pore space occupied by water is connected. Taking into consideration the expressions of R_o and F given by Eqs. 1.9 and 1.10, Eq. 1.38 becomes

$$R_t=(\tau'/\tau)^2(\tau^2R_w/\phi S_w)$$
$$=(\tau'/\tau)^2(FR_w/S_w)$$
$$=(\tau'/\tau)^2(R_o/S_w), \quad \text{(1.39)}$$

and finally

$$S_w=\left(\frac{\tau'}{\tau}\right)^2\frac{R_o}{R_t}=\left(\frac{\tau'}{\tau}\right)^2/I_R. \quad \text{(1.40)}$$

Eq. 1.40 is not practical, however, because the two parameters τ and τ' are complex and cannot be measured. Archie,[7] using experimental studies of clean formations, arrived at the following empirical relationship:

$$S_w^n=1/I_R. \quad \text{(1.41)}$$

The saturation exponent, n, depends on rock type, primarily the manner in which the pores are connected. Values of n ranging from 1 to 2.5 have been reported in the literature. n has been shown to assume higher values in oil-wet formations. Using the expressions of I_R, R_o, and F given by Eqs. 1.35, 1.9, and 1.15 allows Eq. 1.41 to be written as

$$S_w=(R_o/R_t)^{1/n}, \quad \text{(1.42)}$$
$$S_w=(FR_w/R_t)^{1/n}, \quad \text{(1.43)}$$

or $$S_w=(aR_w/\phi^mR_t)^{1/n}. \quad \text{(1.44)}$$

Eqs. 1.42 through 1.44 are used to calculate water saturation in reservoir rocks. The value of n can be determined from laboratory

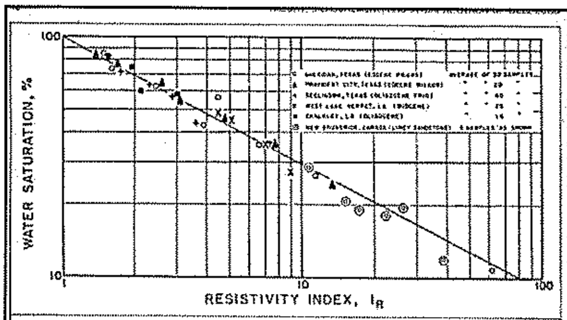


Fig.1.10—Resistivity index vs. water saturation data showing n = 1.9 (from Ref. 15).

measurement with a sample or samples of the formation of interest. The resistance of the samples is first measured at different values of S_w. The resistance data are then used to calculate R_t and I_R. A log-log plot of I_R vs. S_w is linear (Fig. 1.18). The slope of the line that passes through the data points and the chart origin Point (1,1) defines n. Such measurements are delicate. It is necessary to desaturate the samples and then determine the new saturation without any water evaporating from the core during the process.

For clean, consolidated sands, the value of n appears to be close to 2.0, so an approximate generalized relation can be written as

$$S_w = \left(\frac{R_o}{R_t}\right)^{½} = \left(\frac{FR_w}{R_t}\right)^{½} = \left(\frac{aR_w}{\phi^m R_t}\right)^{½} \quad \text{(1.45)}$$

This generalized equation, known as Archie's equation, is the result of a study[13] in which the resistivities of 152 cores from ac-

$(1-S_w)$ is the fraction of the pore volume occupied by hydrocarbons.

Archie determined experimentally that the water saturation of a clean formation can be expressed in terms of its true resistivity as

$$S_w^n = \frac{FR_w}{R_t}, \quad \text{(Eq. 2-4a)}$$

where n is the saturation exponent.

Although laboratory measurements do show some variation in the value of n, most formation samples yield a saturation exponent of about 2. Therefore, in log interpretation practice, n is taken equal to 2 unless it is known to be otherwise.

Accepting n = 2, Eq. 2-4a may be written as

$$S_w = \sqrt{\frac{FR_w}{R_t}}. \quad \text{(Eq. 2-4b)}$$

This equation is often popularly referred to as the Archie water saturation equation. It is the foundation stone of most electrical log interpretation techniques.

In Eq. 2-3, FR_w is equal to R_o, the resistivity of the formation when 100% saturated with water of resistivity R_w. The water saturation equation, Eq. 2-4b, may then be written:

$$S_w = \sqrt{\frac{R_0}{R_t}}. \quad \text{(Eq. 2-5)}$$

Early quantitative electric log interpretation used this formula. It simply involved the comparison of R_t, recorded in a potential hydrocarbon-bearing reservoir rock, to R_o recorded in a known 100% water-bearing reservoir

hydrocarbon viscosity; it generally increases as the viscosity increases.

The comparison of the water saturations obtained in the flushed zone (Eq. 2-6) and in the noninvaded zone (Eq. 2-4b) determines the bulk-volume fraction of oil displaced by the invasion process. Since $S_h = (1-S_w)$ and $S_{hr} = (1-S_{xo})$, the bulk volume of moved oil is $\phi(S_{xo} - S_w)$. The ability of the mud filtrate to displace or move oil in the invasion process implies that the formation exhibits relative permeability to oil; conversely, oil production can be expected when the reservoir is put on production.

Eqs. 2-4b and 2-6 can also be combined to yield the ratio of the saturation in the virgin, uncontaminated zone to the saturation in the flushed zone. Dividing the first equation by the second gives

$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{½}. \quad \text{(Eq. 2-7)}$$

Empirical observations suggest that $S_{xo} = S_w^{⅕}$. Substituting this relationship into Eq. 2-7 gives

$$S_w = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{⅝}. \quad \text{(Eq. 2-8)}$$

Chart Sw-2 is a graphical solution of this equation. The chart also provides for S_w solutions when the residual oil saturation is other than average.

This method for determining water saturation is sometimes referred to as the ratio method. It does not require knowledge of porosity or formation factor. It does, however, imply finite values for these parameters. The implied values can be obtained by working back

$$F = \frac{a}{\phi^m}, \quad \text{(Eq. 2-2)}$$

where m is the cementation factor or exponent. The cementation exponent and the constant a are determined empirically.

Over the years, experience has generated general acceptance of the following formation factor-porosity relationships (dependent on lithology or pore structure):

$$F = \frac{0.62}{\phi^{2.15}} \text{ for sands, and} \quad \text{(Eq. 2-3a)}$$

$$F = \frac{1}{\phi^2} \quad \text{(Eq. 2-3b)}$$

for compacted formations.

The first relationship is popularly referred to as the Hum-

Formation Factor and Porosity

Nonshaly formation rock 100% with brine. R_w

$F = \frac{R_o}{R_w}$ remains nearly constant

Archie observation formulae

$F = \frac{a}{\phi^m}$ (m = Cementation E)

Sands

$F = \frac{0.62}{\phi^{2.15}}$ Humble unconsolidated S

Compacted formation for Carbonates

$F = \frac{1}{\phi^2}$ Chalky rocks / Shaly Sand.

Humble formula Consolidated S

$F = \frac{0.81}{\phi^2}$ Sucrosic rocks (equi-granular)

Compact

or Oolicastic Rocks $F = \frac{1}{\phi^{2.2}} \to \frac{1}{\phi^{2.5}}$ carbonate

FORMATION FACTOR & POROSITY

$F = \frac{R_o}{R_w} = \frac{a}{\phi^m}$

$F = \frac{0.62}{\phi^{2.15}}$ } For Sand - Humble

$F = \frac{0.81}{\phi^2}$

$F = \frac{1}{\phi^2}$ for Compacted formation Archie

WATER SATURATION

$S_w^n = \frac{FR_w}{R_t}$ Clean formation: Archie

$S_w = \sqrt{\frac{FR_w}{R_t}}$; n = 2

$S_w = \sqrt{\frac{R_o}{R_t}}$ — (1)

In Flushed Zone

$S_{xo} = \sqrt{\frac{FR_{mf}}{R_{xo}}}$ — (2)

(1)/(2) and $S_{xo} = S_w^{1/5} \Rightarrow S_w = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{5/8}$

$$F = \frac{1}{\phi^2} \quad \text{(Eq. 2-3b)}$$

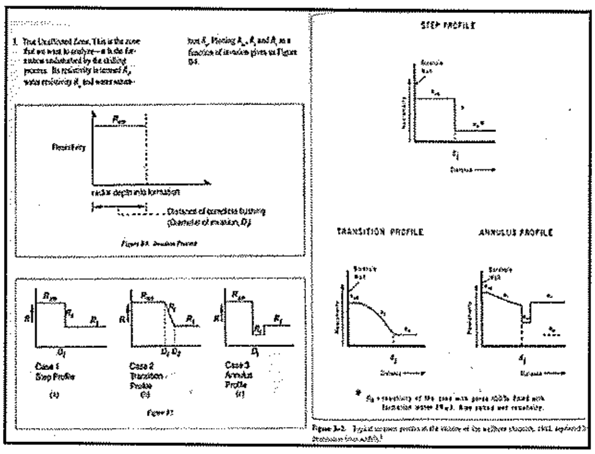
for compacted formations.

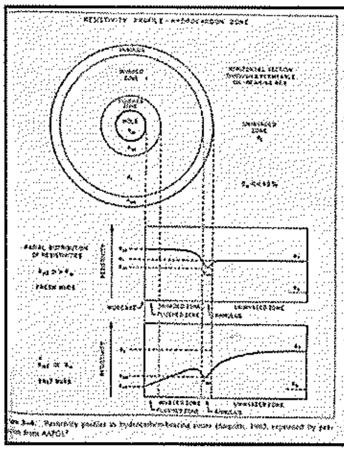
The first relationship is popularly referred to as the Humble formula; the second, as the Archie formation factor relationship.

To eliminate the fractional cementation exponent, the Humble formula is sometimes simplified to

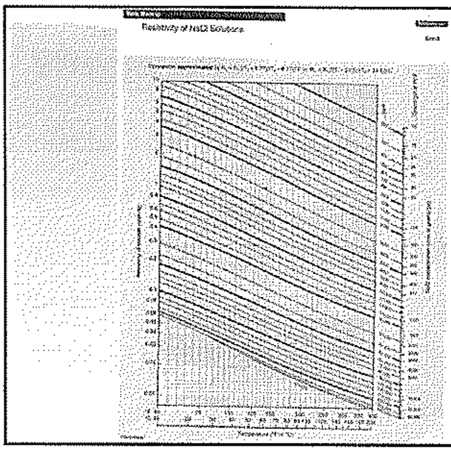
$$F = \frac{0.81}{\phi^2}. \quad \text{(Eq. 2-3c)}$$

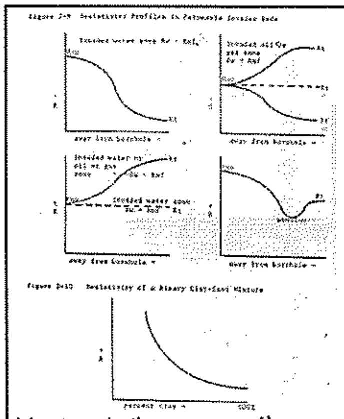
Within their normal range of application, these two ways of expressing the Humble formula yield quite similar results.



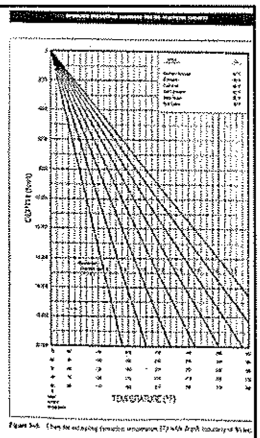


Resistivity of NaCl Solutions

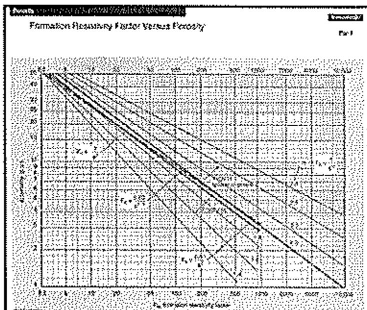




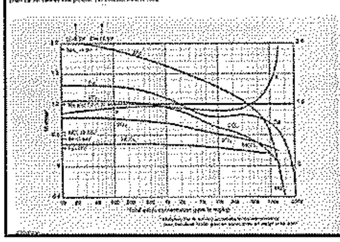
Shale+clay wet with water → conductive



Formation Resistivity Factor Versus Porosity



Resistivities of Solutions



HW NO 2-1; DO THE PROBLEM CHAPTER 2: 2.3, 2.5 AND 2.7

DUE DATE; FRIDAY 25 January 2013

2,3,25 AND 27 ... perature is 100°F. The Rt is ... ration of this zone and would y... a producing zone?

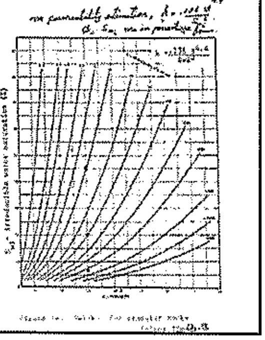
DUE DATE:

FRIDAY 25 January 2013

7. The sandstone you have just logged ... an Rw of .2 at Tf. The Rt is 22 ohm m. What is the water saturation for this zone. What is your estimate of the permeability if this is an oil zone? What would the permeability ... were a gas zone?

8. Rt = 20 ohm m., porosity is 18%, ... ohm m. Determine the changes in S... off by +20%.

Figure 1-1 shows an empirical relationship developed by Timur that shows, for a granular system, irreducible water saturation, porosity and permeability for a medium gravity crude. For a dry gas the indicated permeabilities are too high by a factor of 10. For example if you have a reservoir rock with a porosity of ... and a permeability of 50 md. and it is oil bearing the irreducible water saturation will be about 30%. If the rock is gas bearing the irreducible water saturation will be more like ... The irreducible water saturation is the water saturation well above the transition zone. The transition zone is that range of water saturations which allow both water and hydrocarbon to flow.



1.10 A Frio water from the Texas field in Arkansas has a measured resistivity of 0.131 Ω·m at 68°F and the following ionic composition.

Ionic Constituent	Concentration (ppm)
Na	21,899
Ca	2,499
Mg	382
Cl	38,292
SO_4	381
HCO_3	1,098
CO_3	0
	n_t = 64,551

a. Using the multipliers method, calculate the equivalent NaCl concentration of this water.
b. Estimate the resistivity of this water at 68°F from its chemical analysis.
c. If only the chloride content (i.e., Cl = 38,292 ppm) had been known for this water, what resistivity would you estimate, assuming that the water contains only NaCl salt?
d. For electric log interpretation, can this water be considered pure NaCl? Explain.

1.18 a. Calculate the resistivity at 150°F of a sandstone that is 100% saturated with water. The water salinity is 20,000 ppm and the sand porosity is 12%.
b. Calculate the resistivity at 300°F of a gas-bearing sandstone if gas saturation = 50%, formation water salinity = 200,000 ppm, and formation porosity = 35%.
c. Can the absolute value of the resistivity, R_t, indicate the presence or absence of hydrocarbons? Explain.

Problem 1.10 a. 62,750 ppm.
b. R_w = 0.119 Ω·m.
c. 63,100 ppm and 0.119 Ω·m.
d. Yes.

Problem 1.18 a. R_o = 9 Ω·m using a = 0.81 and m = 2.
b. R_t = 0.32 Ω·m.
c. No.

HW NO 2-3;

DO THE PROBLEM ; 1.10 and 1.18

In the hand out sheet

Due date: Friday 27 Jan 2012

HW NO 2-2;

DO THE PROBLEM 5

In the hand out sheet

Due date:

Friday 25 Jan 2013

3. ... S_w = 24% and R_t = 50? ... = 42% and ... 4. ... an uncertainty in n ranging ... and R_t = 25?

5. (a) A thick, clean sand was drilled having a resistivity of 0.2 Ωm in the upper portion and a resistivity of 1.1 Ωm in the lower portion. If the lower part of the sand is assumed to be water bearing (S_w = 100%) and if it is also assumed that ϕ, m and R_w remain constant throughout the formation, what is the apparent hydrocarbon saturation in the upper part of the formation for a value of n = 1.9?

(b) For the same sand as described in part (a), what would be the range in hydrocarbon saturation in the upper zone if an uncertainty in n of from 1.8 to 2.0 were admitted?

(c) For the same sand as described in part (a), what would be the range in hydrocarbon saturation in the upper zone for m = 1.8 if an uncertainty in both n and ϕ were admitted such that n might range from 1.8 to 2.0 and ϕ might vary from 18% to 22% (18% in the upper zone to 22% in the lower zone or vice versa)?

1.10 A Frio water from the Texas field in Arkansas has a measured resistivity of 0.131 Ω·m at 68°F and the following ionic composition.

Ionic Constituent	Concentration (ppm)
Na	21,899
Ca	2,499
Mg	382
Cl	38,292
SO_4	381
HCO_3	1,098
CO_3	0
	n_t = 64,551

a. Using the multipliers method, calculate the equivalent NaCl concentration of this water.
b. Estimate the resistivity of this water at 68°F from its chemical analysis.
c. If only the chloride content (i.e., Cl = 38,292 ppm) had been known for this water, what resistivity would you estimate, assuming that the water contains only NaCl salt?
d. For electric log interpretation, can this water be considered pure NaCl? Explain.

Problem 1.10 a. 62,750 ppm.
b. R_w = 0.119 Ω·m.
c. 63,100 ppm and 0.119 Ω·m.
d. Yes.

Problem 1.18 a. R_o = 9 Ω·m using a = 0.81 and m = 2.
b. R_t = 0.32 Ω·m.
c. No.

HW NO 2-3;

DO THE PROBLEM ; 1.10 and 1.18

In the hand out sheet

Due date: Friday 27 Jan 2012

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5. (a) A thick, clean sand was drilled having a resistivity of 0.2 Ωm in the upper portion and a resistivity of 1.1 Ωm in the lower portion. If the lower part of the sand is assumed to be water bearing (S_w = 100%) and if it is also assumed that ϕ, m and R_w remain constant throughout the formation, what is the apparent hydrocarbon saturation in the upper part of the formation for a value of n = 1.9?

(b) For the same sand as described in part (a), what would be the range in hydrocarbon saturation in the upper zone if an uncertainty in n of from 1.8 to 2.0 were admitted?

(c) For the same sand as described in part (a), what would be the range in hydrocarbon saturation in the upper zone for m = 1.8 if an uncertainty in both n and ϕ were admitted such that n might range from 1.8 to 2.0 and ϕ might vary from 18% to 22% (18% in the upper zone to 22% in the lower zone or vice versa)?

HW NO 2-2;

DO THE PROBLEM 6

In the hand out sheet

Due date:

Friday 25 Jan 2013

S_w = .327 = 32.7%

(b) n = 1.8 S_w = 30.7%
n = 2.0 S_w = 34.6%

30.7% < S_w < 34.6%
65.4% < S_{hc} < 69.3%

for maximum I_{Ru}, 1.8 < n < 2
25.2% < S_w < 28.3%

for minimum I_{Ru}, 1.8 < n < 2
37.5% < S_w < 41.3%
58.6% < S_{hc} < 74.8%

HW NO 2-3;

DO THE PROBLEM 1.7 and 1.10

In the hand out sheet

Due date: Friday 25 Jan.2013

1.7 1.41 lbm of NaCl is dissolved in 1 gal of water. The volume increases to 1.06 gal. Water weighs 8.34 lbm/gal at 60°F.
a. What is the salinity of the water in ppm--i.e., parts of salt by weight per million parts of salt water by weight?
b. What is the salinity in mg/L of salt water?
c. What is the normality of the solution?
d. What is the salinity in grains per gallon?
e. What is the resistivity of the solution at 100 and 200°F?

Problem 1.7 a. 145,000 ppm.
b. 159,400 mg/L.
c. 2.72 g eq/L.
d. 8,456 grains/gal.
e. 0.043 Ω·m and 0.025 Ω·m.

Problem 1.8 a. 170,000 ppm.

Problem 1.10 a. 62,750 ppm.
b. R_w = 0.119 Ω·m.

1.10 A Frio water from the Texas field in Arkansas has a measured resistivity of 0.131 Ω·m at 68°F and the following ionic composition.

Ionic Constituent	Concentration (ppm)
Na	21,899
Ca	2,499
Mg	382
Cl	38,292
SO_4	381
HCO_3	1,098
CO_3	0
	n_t = 64,551

a. Using the multipliers method, calculate the equivalent NaCl concentration of this water.
b. Estimate the resistivity of this water at 68°F from its chemical analysis.
c. If only the chloride content (i.e., Cl = 38,292 ppm) had been known for this water, what resistivity would you estimate, assuming that the water contains only NaCl salt?
d. For electric log interpretation, can this water be considered pure NaCl? Explain.

Problem 1.10 a. 62,750 ppm.
b. R_w = 0.119 Ω·m.
c. 63,100 ppm and 0.119 Ω·m.
d. Yes.

1.10 A Frio water from the Texas field in Arkansas has a measured resistivity of 0.131 Ω·m at 68°F and the following ionic composition.

Ionic Constituent	Concentration (ppm)	K_i	K_iC_i
Na	21,899	1	21,899
Ca	2,499	0.75	1,874
Mg	382	0.52	217
Cl	38,292	1	38,292
SO_4	381	0.54	130
HCO_3	1,098	0.20	220
CO_3	0	0.30	
	n_i = 64,551		62,728

40

a. Using the multipliers method, calculate the equivalent NaCl concentration of this water.
b. Estimate the resistivity of this water at 68°F from its chemical analysis. 0.119 Ω·m
c. If only the chloride content (i.e., Cl = 38,292 ppm) had been known for this water, what resistivity would you estimate, assuming that the water contains only NaCl salt?
d. For electric log interpretation, can this water be considered pure NaCl? Explain.

c. Na, Ca, Mg, Cl
≈ 63,073
Resistivity ≈ 0.119 Ω·m
d. yes, NaCl

Problem 1.10 a. 62,750 ppm.
b. R_w = 0.119 Ω·m.
c. 63,100 ppm and 0.119 Ω·m.
d. Yes.

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22 THEORY, MEASUREMENT, AND INTERPRETATION OF WELL LOGS

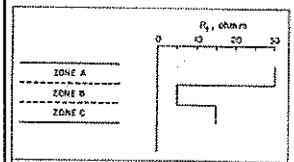

Fig. 1.33—Resistivity profile of Problem 1.22.

	Lithology	Average m	Average n
Wilcox, U.S. gulf coast	SS	1.9	1.8
Sparta, south Louisiana (Opelousas)	SS	1.9	1.6
Cockfield, south Louisiana	SS	1.8	2.1
Government wells, south Texas	SS	1.7	1.9
Frio, south Texas	SS	1.8	1.8
Miocene, south Texas	Cons. SS	1.95	2.1
	Uncons. SS	1.6	2.1
Travis Peak and Cotton Valley, TX	SS	1.8	1.7
Rodessa, east Texas	LS	2.0	1.6
Edwards, south Texas	LS	2.0	2.8
Woodbine, east Texas	SS	2.0	2.5
Annona, north Louisiana	Chalk	2.0	1.5
Nacatoch, Arkansas	SS	1.9	1.3
Ellenburger, west Texas	LS and Dol.	2.0	1.9

1.18 a. Calculate the resistivity at 150°F of a sandstone that is 100% saturated with water. The water salinity is 20,000 ppm and the sand porosity is 12%.
b. Calculate the resistivity at 360°F of a gas-bearing sandstone if gas saturation = 50%, formation water salinity = 200,000 ppm, and formation porosity = 35%.
c. Can the absolute value of the resistivity, R_t, indicate the presence or absence of hydrocarbons? Explain.

1.19 The following data pertain to an oil formation: F vs. φ relation given by Fig. 1.10; I vs. S_w relation given by Fig. 1.18; formation resistivity measured in situ by an appropriate logging device = 7 Ω·m; formation water resistivity determined from water sample chemical analysis = 0.01 Ω·m; and formation porosity from an appropriate logging device = 17%. Give your best estimate of the formation oil saturation.

1.20 The following data pertain to a sandstone formation: formation porosity = 17%; formation water resistivity at 70°F = 0.17 Ω·m; formation temperature = 160°F; and formation resistivity = 56 Ω·m at 160°F.
a. What is the formation resistivity factor of this sandstone?
b. Calculate the resistivity R_o of this formation.
c. Does this formation contain hydrocarbons?

1.21 a. A clean limestone water-bearing formation displays a true resistivity of 7.0 Ω·m and formation water resistivity of 0.02 Ω·m. Give your best estimate of the formation porosity.
b. An adjacent oil-bearing limestone zone displays a true resistivity of 28 Ω·m. Give your best estimate of the oil saturation.
c. To estimate the value of oil saturation in Part b, you had to opt for several assumptions. What are these assumptions and how do you justify each of them?

1.22 The following data pertain to a carbonate formation: formation thickness = 15 ft; formation water salinity = 95,000 ppm;

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and the dual-water models expressing shaly-sand conductivity.

Problems **MW of NaCl= 58.5**

1.1 A tube that is 12.0 cm long and 2.0 cm in diameter that contains saline water passes a current of 25 mA under a voltage drop of 15 V.
a. What is the r... of the water?
b. What is its re...
c. What is its re...
d. What is the conductance of the water?
e. What is the conductivity in ...

HW NO 2-3;

DO THE PROBLEM : 1.7 and 1.10

in the hand out sheet

Due date: Friday 25 Jan 2012

length d. A cylindrical hole of diameter d is drilled through the bl...
a. Det...
b. Wh... formation factor, F, and the porosity, φ, for this rock?

a. Determine the porosity of the rock.
b. Calculate the formation resistivity factor of this rock.
c. What is the cementation exponent, m, of this rock that would satisfy a relation of the form $F = \phi^{-m}$?
d. In what type of rock might the m calculated above apply?

1.4 A cylindrical clean sandstone core plug 2.0 cm in diameter and 6.0 cm in length is 100% saturated with a saline water of resistivity R_w = 0.10 Ω·m. For a potential drop of 5.7 V (from end to end), the saturated core will pass a current of 15 mA.
a. What is the resistivity of this rock?
b. What is the formation resistivity factor for this core?
c. Using the above data, estimate the porosity of the core plug.

core is partially desaturated. Its mass is now 57.03 g. Calculate the water saturation.
f. For an exponent n of 2, what would be the end-to-end resistance of the core and its true resistivity?

1.6 a. Calculate the mass of NaCl and H_2O needed to prepare, at a room temperature of 25°C, 1 L of brine having a salinity of 150 g/L.
b. Calculate the volume occupied by the dissolved NaCl.

1.7 1.41 lbm of NaCl is dissolved in 1 gal of water. The volume increases to 1.06 gal. Water weighs 8.34 lbm/gal at 60°F.
a. What is the salinity of the water in ppm—i.e., parts of salt by weight per million parts of salt water by weight?
b. What is the salinity in mg/L of salt water?
c. What is the normality of the solution?
d. What is the salinity in grains per gallon?
e. What is the resistivity of the solution at 100 and 200°F?

1.8 a. What is the salinity of an NaCl solution whose resistivity is 0.02 Ω·m at 200°F?
b. The resistivity of an NaCl solution obtained from laboratory measurements was reported as being 0.01 Ω·m at 60°F. Show this is an erroneous value.

1.9 The viscosity of fresh water at various temperatures is as follows:

Temperature (°F)	Viscosity (cp)
50	1.30
100	0.68
150	0.43
200	0.30
250	0.23
300	0.19

a. Plot viscosity, in ordinate, vs. temperature on linear coordinate paper.
b. Show that the viscosity can be approximately calculated with the equation $\mu = 60/T$, where μ is in cp and T is in °F.
c. On the same graph, plot, in ordinate, ...

Appendix B
Answers to Selected Problems

Chapter 1

Chapter 2

ELECTRICAL RESISTIVITY OF ROCKS

suitable change in ordinate scale, plot the resistivity of a 60,000-ppm NaCl solution.
d. What conclusion do you draw from Part c about the mechanism by which temperature affects the resistivity of electrolytes?

1.10 A Frio water from the Texas field in Arkansas has a measured resistivity of 0.131 Ω·m at 68°F and the following ionic composition.

Ionic Constituent	Concentration (ppm)
Na	21,899
Ca	2,499
Mg	382
Cl	38,292
SO_4	381
HCO_3	1,098
CO_3	0
	n_i = 64,551

a. Using the multipliers method, calculate the equivalent NaCl concentration of this water.
b. Estimate the resistivity of this water at 68°F from its chemical analysis.
c. If only the chloride content (i.e., Cl = 38,292 ppm) had been known for this water, what resistivity would you estimate, assuming that the water contains only NaCl salt?
d. For electric log interpretation, can this water be considered pure NaCl? Explain.

1.11 Repeat Problem 1.10 for the formation water whose composition is given in Example 1.4.

1.12 Figs. 1.12 and 1.13 are plots of data used to derive the Hum-

23x	3.00	18.01	31.57	3
24	2.50	13.44	27.96	2
26	3.00	15.72	31.01	2

a. Calculate the porosity and formation resistivity factor of each core.
b. Plot φ vs. F on a 2×3 cycle log-log paper.
c. Can these data be fitted satisfactorily by a relation of the form $F = a\phi^{-2}$? If so, determine the value of the coefficient a.

1.15 A sandstone core sample (d = 1.90 cm and L = 3.20 cm) is saturated with a brine of 0.55-Ω·m resistivity. The core was desaturated in steps, and the following resistances were measured at each saturation.

S_w (fraction)	r (Ω)
1.000	521
0.900	678
0.800	913
0.730	1,151
0.640	1,510
0.560	2,255
0.480	3,135
0.375	5,270
0.350	6,820
0.300	10,400

a. Estimate the rock porosity.
b. Determine the saturation exponent, n, of the rock.

1.16 Special core analyses were performed on several core plugs recovered from a wildcat well. Identification and description of the samples and formation factor and resistivity index d...

If yes, determine the values of m.

1.13 The resistivity of a water-bearing sand was found to be 0.4 Ω·m. If the formation water resistivity is 0.02 Ω·m, give your best estimate of the formation porosity. What is the statistically possible range of porosity in this sand?

1.14 Several sandstone samples were used to investigate the relationship between the formation resistivity factor and porosity. Each sample is a cylindrical plug with d = 2 cm and L ranging from 2.5 to 3.10 cm. These plugs were taken from a large-diameter core. The samples were cleaned, dried, and weighed. They were then fully saturated with a 50,000-ppm brine and reweighed; their resistances were also measured. In the weighing process, the sample was placed in a 13.04 g cylindrical container to prevent the brine from evaporating. All measurements were conducted at 70°F. The data collected are listed below.

Core	Length (cm)	Dry Core Weight (g)	Saturated Core Weight Plus Bottle (g)	r_o (Ω)
11	3.05	20.59	34.64	810
12	3.05	19.13	33.53	520
13	3.05	19.68	33.90	580
14	3.00	21.09	34.84	2,200
14x	3.10	21.21	35.04	2,100
15	3.05	18.60	33.03	465
16	3.05	19.37	33.62	1,000
17	3.05	20.70	34.64	1,100
18	3.05	19.31	33.68	500
19	3.00	19.37	33.64	830
20	3.05	17.84	32.58	360
22	3.00	18.65	33.25	460

Identification and Description of Samples

Sample	Depth (ft)	Lithological Description
1	2,915.8	Limestone with shale streaks
2	2,916.8	Limestone with shale streaks
3	2,917.4	Limestone with shale streaks, few vugs
4	2,918.4	Limestone with shale streaks
5	2,919.4	Limestone with shale streaks, secondary calcite
6	2,920.4	Limestone with shale streaks, secondary calcite
10	2,927.3	Limestone with shale streaks

Formation Factor and Resistivity Index Data

Sample	Porosity (%)	Formation Factor	Brine Saturation (% Pore Space)	Resistivity Index
1	11.6	59.0	100.0	1.00
			85.4	1.42
			29.5	8.56
			17.3	25.30
4	10.2	70.9	100.0	1.00
			93.2	1.17
			42.6	4.26
			16.7	20.20
6	6.1	153.0	100.0	1.00
			69.7	1.79
			31.8	6.41
10	2.9	603.0	100.0	1.00

1.17 The following table lists average values of m and n obtained

Resistivity Logs

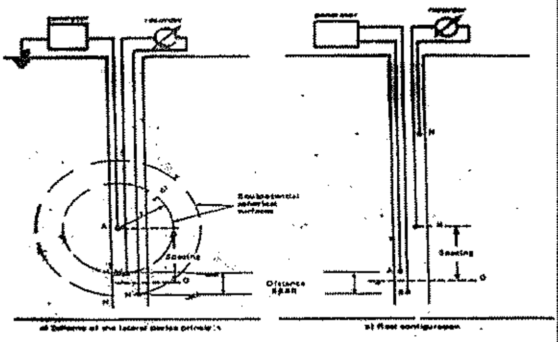


Fig 3-3 The Lateral Configuration

Dual Induction Log presentation   Induction SFL presentation

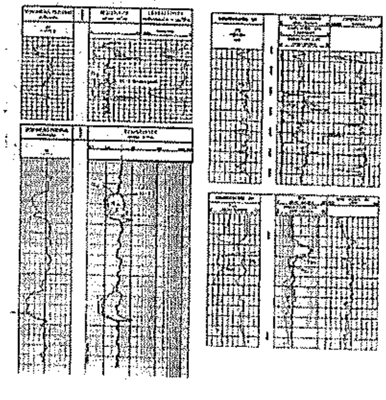


Fig 9.12

Resistivity Logs

Normal

Lateral

Conductivity

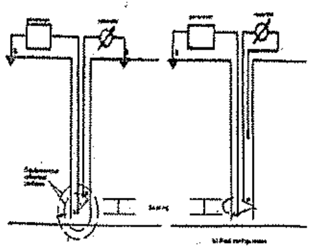


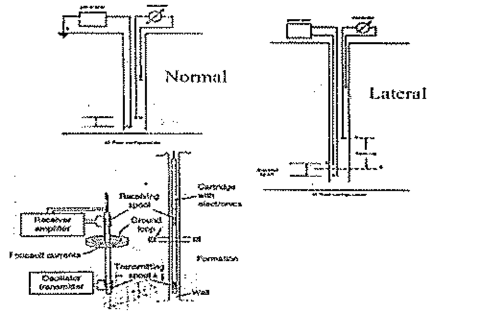
Fig 3-3 The normal configuration

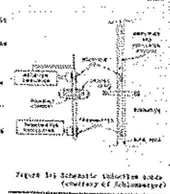
Fig 9.10 Classification of Resistivity Log

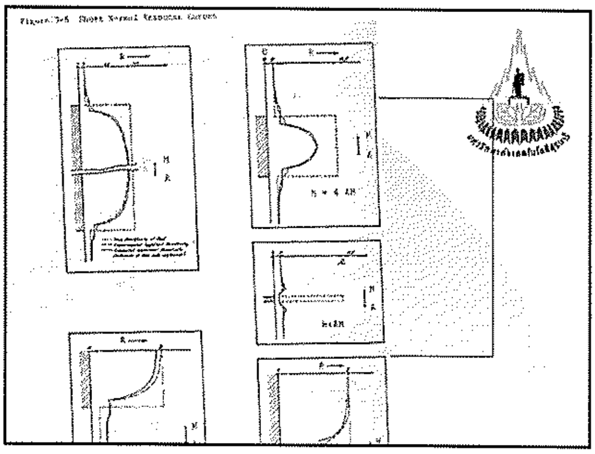
TABLE 3-1. Classification of resistivity logs

Flushed Zone (R_{xo})	Invaded Zone (R_i)	Uninvaded Zone (R_t)
Microlog	Short Normal	Long Normal
Microlaterolog	Laterolog-8 (LL8)	Laterolog
Proximity Log	Spherically Focused Log (SFL)	Deep Induction Log
Microspherically Focused Log (MSFL)	Medium Induction	Deep Laterolog (LLD)
	Shallow Laterolog (LLS)	Laterolog-3 (LL3)
		Laterolog-7 (LL7)
		Induction Log (6FF40)

Fig 9.8 Schematic representation of Resistivity and Induction Log







Example 3-2 Induction Borehole Correction

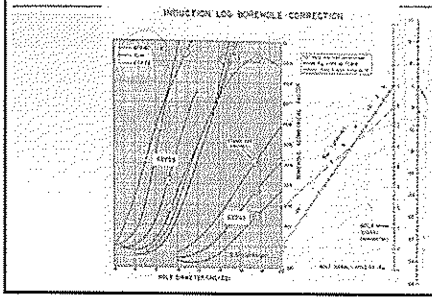
The apparent formation resistivity from the induction log is 25 ohm m. The borehole is 14.6 inches in diameter. The mud resistivity at that depth and temperature is .325 ohm m. The stand-off is 1.5 inches. From figure 3-10 the correction is 5.5 millimhos/m.

Ca = 1000/Ra = 1000/25 = 40

Ca (borehole corrected) = Ca − correction = 40 − 5.5 = 34.5 millimhos/m.

Ra = 1000/34.5 = 29 ohm m.

This example uses a very large borehole and a modestly salty mud so the correction is larger than normally experienced.



Example3-1

Example 3-1 Bed Thickness Corrections for ILd

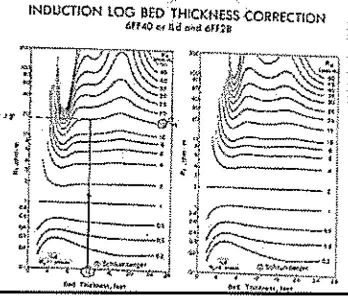
a) For Rs (adjacent bed resistivity) of 1 ohm m, a bed ... and the apparent resistivity of 15 ohm m see the upper left hand chart of figure 3-7. You follow bed thickness vertical until you reach Ra and then read Rt from the scale on the left as Rt = 18 in this case.

b) For a thin conductive bed where Ra is 5 ohm m, the bed thickness is 3 feet and the apparent resistivity from the curve is Ra = R_{ID} = 2 ohm m. The $R_{ID\ cor.}/R_{ID}$ from the chart is .87. Rt or $R_{ID\ cor.}$ = 1.75 ohm m.

Figure 3-7 (courtesy Schlumberger)

INDUCTION LOG BED THICKNESS CORRECTION

6FF40 or ILd and 6FF28



HW NO 3; DO THE PROBLEM CHAPTER 3; 3.2, 3.4, AND 3.5

DUE DATE; FRIDAY 3 February 2012

1. Classify the following ... curves as Rt ... if the curve falls ... classifications ...: deep induction, SFL, short normal, medium induction, 6FF40 laterolog 8.

2. The deep induction reads an apparent resistivity of 22 ohm m in a bed that is 12 feet thick. What is Rt if the adjacent shale bed has a resistivity of 3 ohm m?

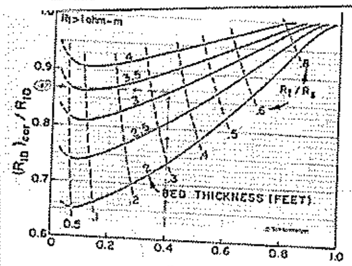
3. A thin bed of 2.5 feet thick has an apparent induction resistivity (ILd) of 2 ohm m. The adjacent bed resistivity is 9 ohm m. What is Rt?

4. A medium induction has an apparent resistivity of 25 ohm m. The bit size is 10.75 inches in diameter and the stand-off is 1.5 inches. If the mud has a resistivity of 1 ohm m @ 75°F and the temperature at that depth is 215°F. What is the resistivity after making a borehole correction?

5. A DIL-SFL shows the following values opposite a formation: R_{ILd} = 3.0, R_{ILm} = 4 and R_{SFL} = 18. What is Rt, diameter of invasion and Rxo according to the charts?

read Rt from the scale on the left as Rt = 18 in this case.

b) For a thin conductive bed where Rs is 5 ohm m, the bed thickness is 3 feet and the apparent resistivity from the curve is Ra = R_{ID} = 2 ohm m. The $R_{ID\ cor.}/R_{ID}$ from the chart is .87. Rt or $R_{ID\ cor.}$ = 1.75 ohm m.



HW NO 3; DO THE PROBLEM CHAPTER 3; 3.2, 3.4, AND 3.5

2. The deep induction reads an apparent resistivity of 22 ohm m in a bed that is 12 feet thick. What is Rt if the adjacent shale bed has a resistivity of 3 ohm m?

DUE DATE; FRIDAY 1 February 2013

4. A medium induction has an apparent resistivity of 25 ohm m. The bit size is 10.75 inches in diameter and the stand-off is 1.5 inches. If the mud has a resistivity of 1 ohm m @ 75°F and the temperature at that depth is 215°F. What is the resistivity after making a borehole correction?

4.Rt-32Ω-m

5. A DIL-SFL shows the following values opposite a formation: R_{ILd} = 3.0, R_{ILm} = 4 and R_{SFL} = 18. What is Rt, diameter of invasion and Rxo according to the charts?

5.Rt-2.79Ω-m, di=48 inches.,

Rxo =27.9Ω-m

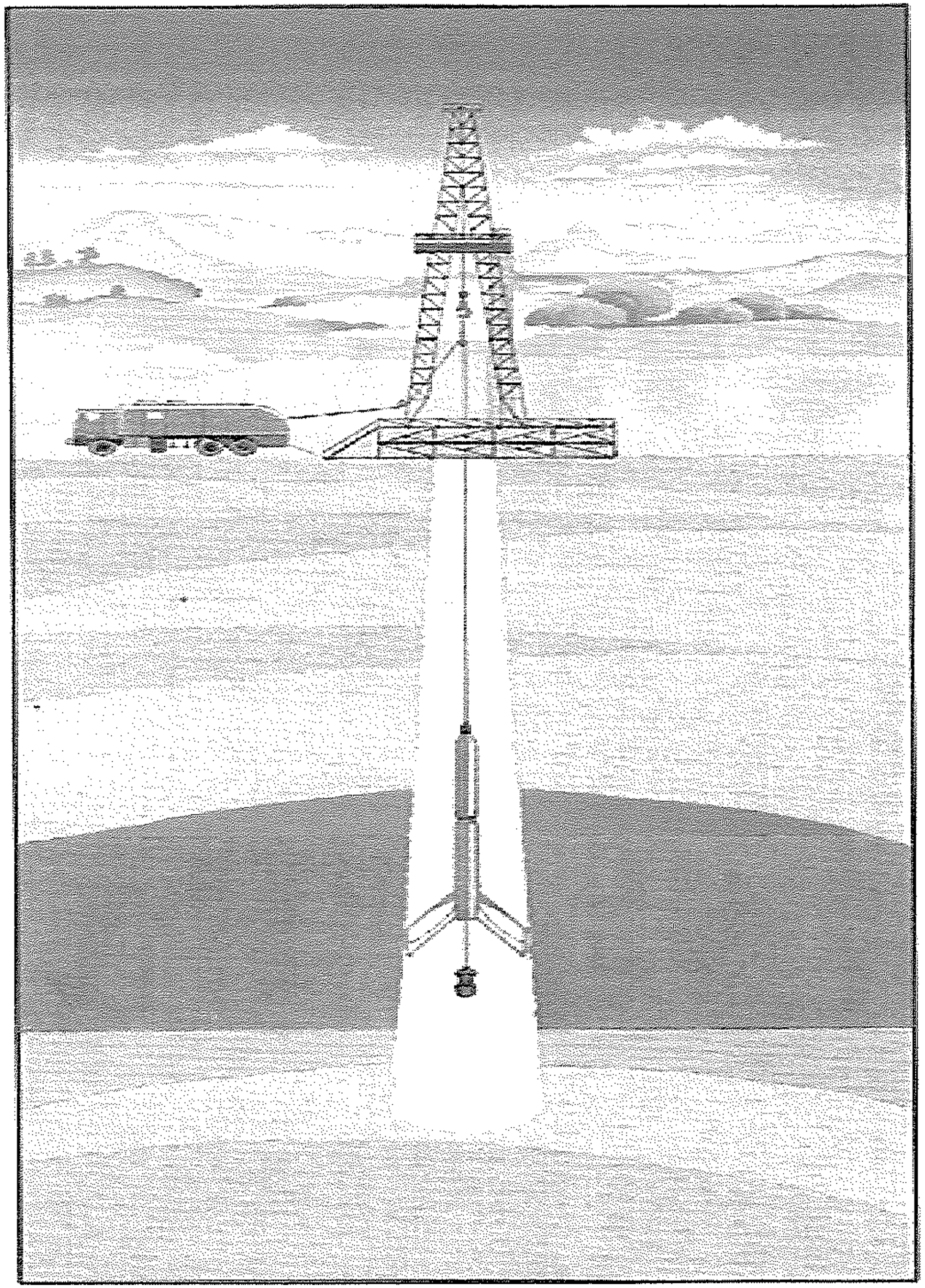


Fig. 1-2—Wireline logging operation.

WELLLOGGING

มหาวิทยาลัยเทคโนโลยีสุรนารี

CHAPTER4
CHAPTER5

434359,505359 WELL LOGGING 2012(3/2554)

COURSE OUTLINES

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)
Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)
Resistivity Device(2 hrs.)
Spontaneous Potential (SP) Log(2 hrs.)
Induction Electric and Dual Induction Logs(2 hrs.)
Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
Openhole Log and QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Fracture Detection with Well Logs(1 hr.)
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)
Special Logs(1 hrs.)
Core & Core Analysis(2 hrs.)

TEXT BOOKS

DOUGLA W. HILCHIE , ***APPLIED OPENHOLE LOG INTERPRETATION,*** (for Geologists and Engineers) Revised 1982.

REFERENCES

Schlumberger , ' LOG INTERPRETATION PRINCIPLES/APPLICATIONS " 1989

M. A. MIAN, " PETROLEUM ENGINEERING Handbook for the Practicing Engineer ', Volume I, PennWell Books , 1992

Petro Canada " Fundamentals of Core Analysis and Special Core Analysis', PTT.EP. Training, 1988.

GRADING

Homework	25 %
Quiz I, II	25 %
Mid Term	20 %
Final Exam	30 %

S P THE SPONTANEOUS POTENTIAL LOG

THIS IS THE SIMPLIEST INFORMATION RECORDED IN OPEN HOLE LOGGING.

THE SP IS USEFUL TO

1. DETECT THE PERMEABLE BED

2. GIVE BED BOUNDARIES for Correlation Purposes

3. EVALUATE Formation Water RESISTIVITY(R_w)

4. GIVE Qualitative Indication of Bed Shaliness(V_{SH})

WHAT IS THE SP

The *SP* is the different of potential between one fixed reference electrode(usually on surface) and a mobile electrode in the bore hole

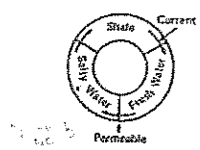


Figure 4-1 Mounce and Rust Model

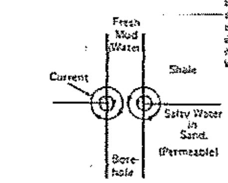
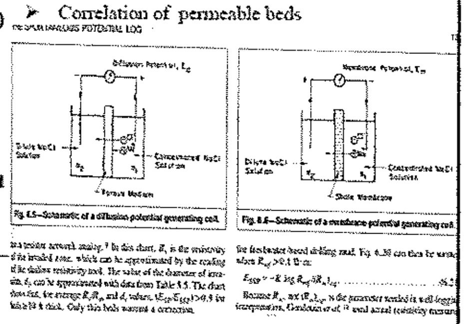


Figure 4-2 The SP cell borehole equivalent

A Schematic for measurement of SP

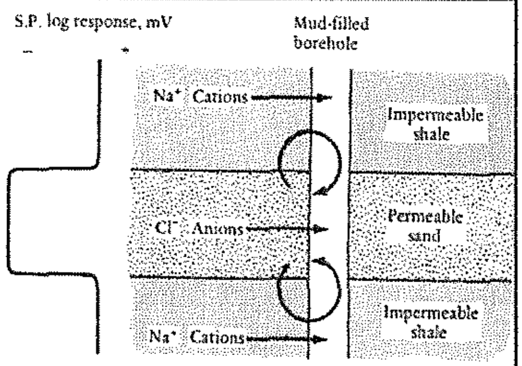
APPLICATION

- To delineate porous and permeable reservoir rocks
- To determine bed boundaries and bed thickness
- To evaluate the formation water resistivity
- To estimate the fraction of clay
- Correlation of permeable beds



Spontaneous Potential is the natural occurring potential due to current flow in the borehole; potential is produced from salinity gradients ([Na^+] and [Cl^-]), ion selective membranes and ion movement between borehole and formation.

The electric charge of SP is caused by the flow of ions (Na^+ and Cl^-) from concentrated to more diluted solutions; so there is a flow from salty formation water to fresher drilling mud near borehole



Applications:
- indicates permeability
- calculation of Rw (formation water resistivity), Sw (water saturation) and Net Pay
- defines bed boundaries
- indicates shale (it closely follows Gamma Ray logs; pseudo g-Ray log)
- correlations and qualitative interpretations (depositional environment)

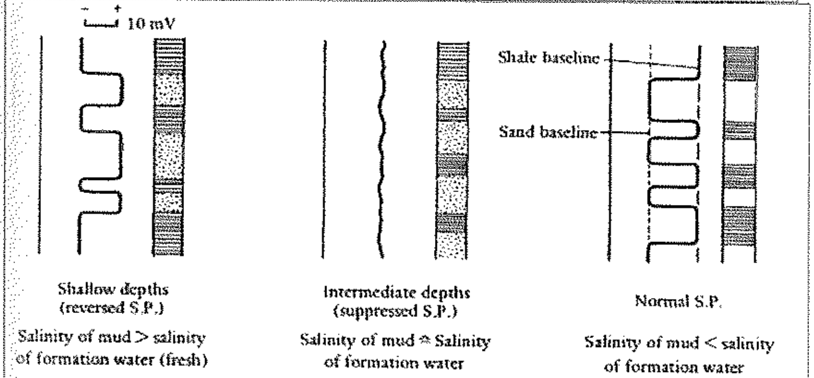
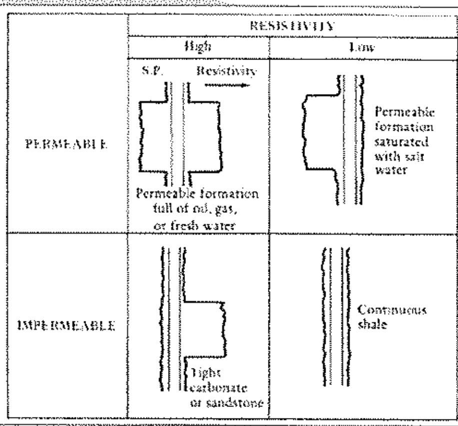
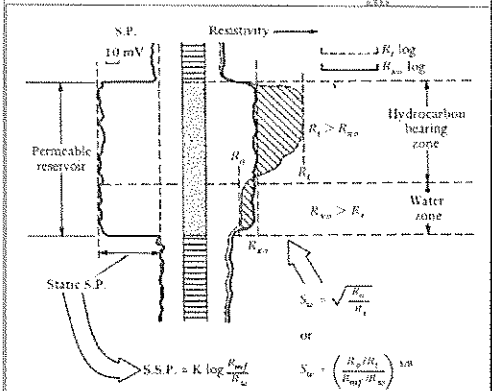


FIGURE 3.20 Schematic S.P. logs for different salinity contrasts of mud and formation water. Reversed S.P. logs are very rare. Suppressed S.P. logs occur where salt muds are used. The usual response, in which the salinity of the drilling mud is less than the salinity of the formation water, is shown in the right-hand log.





Resistivity together with SP are a powerful combination in identifying permeable, fluid-bearing reservoirs

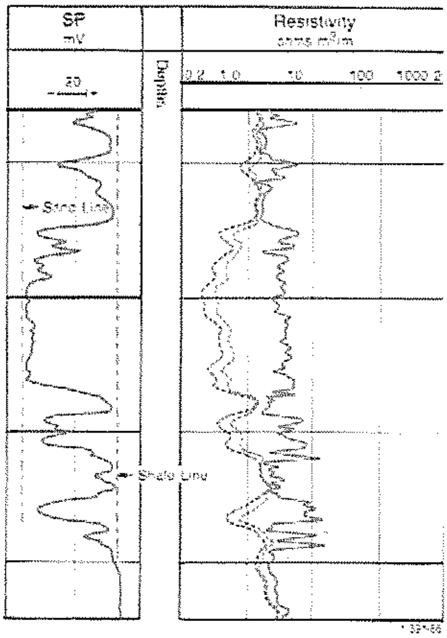


Fig. 3-1—Example of SP log in a sand-shale series.

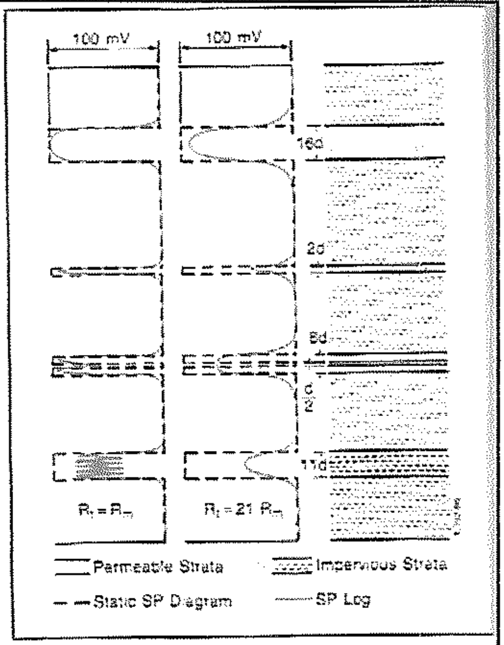
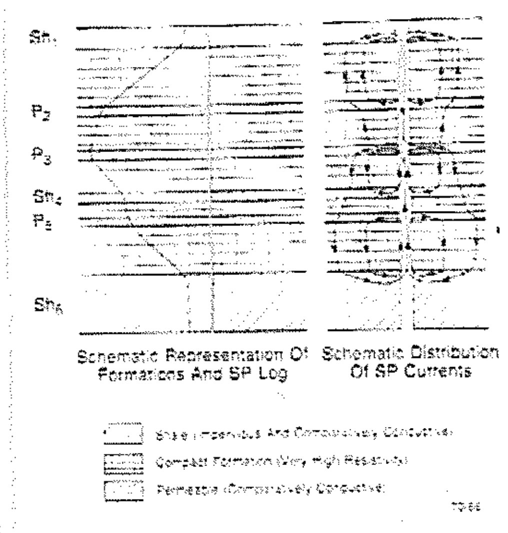


Fig. 3-3—SP curve in beds of different thickness for $R_t = R_m$ (left) and $R_t = 21\ R_m$ (center).



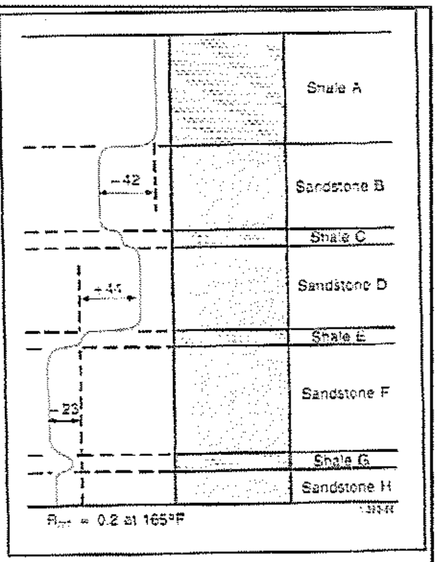


Fig. 3-4—Schematic representation of SP phenomena ... highly resistive formations.

Fig. 3-5—SP baseline shift.

For a clean (non-shaly) formation the electrochemical potential is

$$Ec = - Kc \log \frac{a_w}{a_{mf}} \qquad (4\text{-}1)$$

where Ec is the potential of the cell in millivolts
a_w is the activity of the formation water
a_{mf} is the activity of the mud filtrate
and Kc is proportional to formation temperature and is

$$Kc = .133\ T + 61 \qquad (4\text{-}2)$$

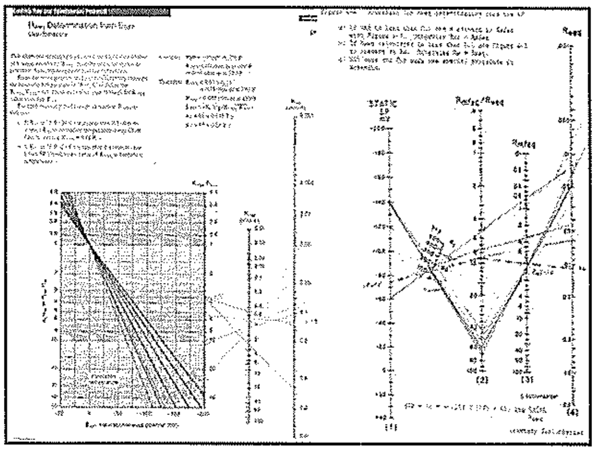
where T is in degrees Fahrenheit.

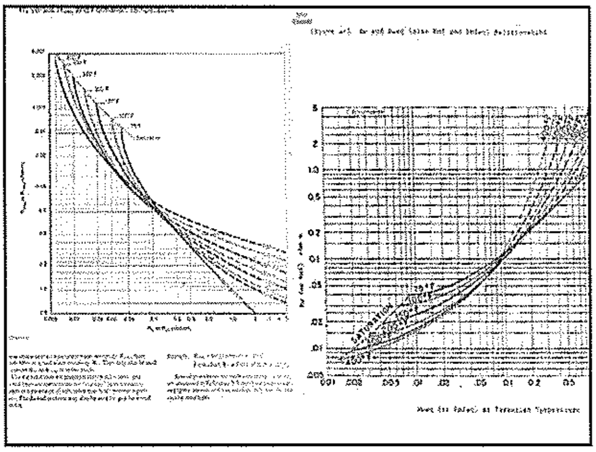
When converted to resistivities euation 4-1 becomes

$$\boxed{Ec = - Kc \log \frac{Rmfeq}{Rweq}} \qquad (4\text{-}3)$$

where Rmfeq is the equivalent resistivity of the mud filtrate
and Rweq is the equivalent resistivity of the formation water.

Figure 4-4 solves equations 4-2 and 4-3 for Rweq. The SP used should be corrected for bed thickness (if necessary). SSP is Ec or SP (corrected) Rmfeq is at formation temperature.





R_w FROM THE SP

In many cases, a good value of R_w can easily be found from the SP curve recorded in clean (nonshaly) formations. The static SP (SSP) value in a clean formation is related to the chemical activities (a_w and a_{mf}) of the formation water and mud filtrate through the formula:

$$SSP = - K \log \frac{a_w}{a_{mf}} \qquad \text{(Eq. 4-1)}$$

For NaCl solutions, $K = 71$ at 77° F (25° C); K varies in direct proportion to temperature:

$$K = 61 + 0.133\ T_{°F} \qquad \text{(Eq. 4-2)}$$

$$K = 65 + 0.24\ T_{°C}$$

R<>

For pure NaCl solutions that are not too concentrated, resistivities are inversely proportional to activities (Fig. 4-1). However, this inverse proportionality does not hold exactly at high concentrations or for all types of waters. Therefore, equivalent resistivities R_{weq} and R_{mfeq}, which by definition are inversely proportional to the activities ($R_{weq} = 0.075/a_w$ at 77° F), are used. R_{weq} is the equivalent formation water resistivity and R_{mfeq} is the equivalent mud filtrate resistivity. Eq. 4-1 can then be written in resistivity terms as:

$$SSP = - K \log \frac{R_{mfeq}}{R_{weq}} \qquad \text{(Eq. 4-3)}$$

Knowing the formation temperature, the static SP value recorded opposite a porous, permeable, nonshaly formation can be transformed into the resistivity ratio

Rw DETERMINATION SP METHOD

Static SP (SSP) is the deflection in m volts of the SP log oppos a permeable bed compared to a non-permeable bed.

$$SSP = - k \log \frac{aw}{amf} = - k \log \frac{Rmfe}{Rwe}$$

NaCl K = 71 at 77°F

1. read SSP from logs
2. correct it for bed thickness — chart SP-3/SP-4
3. read Rmf from heading — Ts cm Fig 2-3 P2-4
4. correct it at formation T — chart GEN-9 — P 4-2
5. get Rmfe — chart SP-1
6. get Rwe — chart SP-1 — Fig 4-4 P 4-5
7. get Rw — chart SP-2 — Fig 4-5 P 4-9

ALGORITHM 1 Rw DETERMINATION FROM SP

1. Establish the shale baseline on the SP
2. Pick out permeable zones
3. Do all the thick zones have about the same SP?
   yes — pick any thick zone
   no — pick thick zone near or the zone you are interested in.
   -If in transitional zone (see figure right) be very careful.
4. Determine formation temperature------ Fig. 2-3 or Eqn. 2-3
   need - surface temp, bottom hole temp, and total depth
5. Determine Rmf and Rm at formation temperature-----Fig. 2-2
6. Read SP amplitude from shale baseline to maximum constant deflection.
7. Determine bed thickness from SP deflection points.
8. Do you need to, or can you correct for bed thickness effects

   if SP looks like: — needs correction — no correction

   needs correction---Read Ri from short normal, SFL or LL ---use Figure 4-8
9. Using SP from step 8 (corrected if necessary) go to ---Fig. 4-4
   Rmf less than 0.1 correct to Rmfeq --Fig. 4-5
   Enter Fig. 4-4 --------- with SP, T_f, Rmf or Rmfeq
   Come out with Rweq
10. Convert Rweq to Rw with Fig. 4-5
    use solid NaCl lines
11. Check Rw from SP against another source if available

Transitional

Text Fig. 4-8 P 4-9

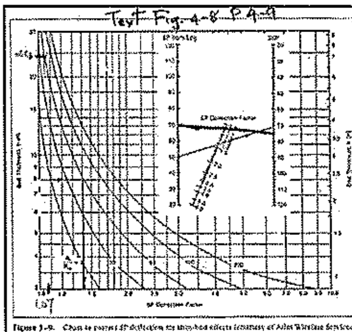


Figure 3-9. Chart to correct SP deflection for thin-bed effects (courtesy of Atlas Wireline Services).

5. If $R_{mf} > 0.10$, $R_{mf} = R_{mfeq}$. If $R_{mf} < 0.10$, correct R_{mf} to R_{mfeq} using Figure 3-10.
6. Use the following equation to calculate the equivalent water resistivity (R_{weq}):

$$\log R_{weq} = \left(\frac{SSP + K \log R_{mfeq}}{K}\right) \qquad (3.3)$$

$$K = 60 + (0.133 \times T_f) \qquad (3.4)$$

7. If $R_{weq} > 0.10$, then $R_{weq} = R_w$, otherwise correct R_{weq} to R_w using Figure 3-12.

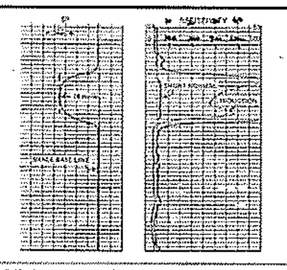


Figure 3-11. SP and resistivity log for Example 3-4 (courtesy of Atlas Wireline Services).

$SSP = 1.07 \times SP$

$= 1.07 \times 70 = -75$ mv

$K = 60 + 0.133 \times T_f$

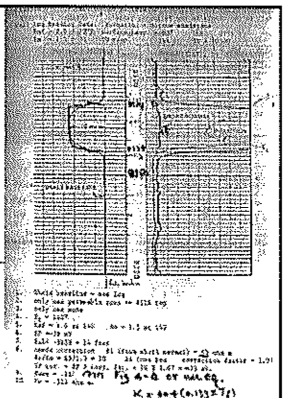
$= 60 + 0.133 \times 140 = 78.62$

$\log R_{we} = \left[\frac{-75 + (78.62)\log(1.0)}{78.62}\right]$

$R_{we} = 0.111$

Since $R_{we} > 0.10$, therefore, $R_w = R_{we} = 0.111$ ohm-m

นักศึกษาจะใช้อัน Fig. ก็ได้ หรือ สูตร R_w ก็ได้



$K = 60 + (0.133 \times T_f)$

Then eq. 4-3

$\log R_{we} = \left(\frac{SSP + K\log R_{mf}}{K}\right)$

Example 3-3. You have just drilled a well to a total depth (TD) of 9,500 ft. The following information was obtained from the SP and resistivity log. The zone of interest is from 8,500 to 8,516 ft.

$T_{BH} = 170°F$ R_t @$T_f = 65$ ohm-m

$T_{ms} = 80°F$ R_{mf} @$70°F = 2.4$ ohm-m

R_m @$T_{BH} = 1.2$ ohm-m $SSP = -70$ mv

Determine the formation temperature and the R_w at the formation temperature.

Solution:

$$T_f = \left(\frac{T_{BH} - T_{ms}}{TD}\right) \times D_f + T_{ms}$$

$$= \left(\frac{170 - 80}{9{,}500}\right) \times 8{,}508 + 80$$

$$= 161°F$$

R_{mf} @$161°F = 1.10$ ohm-m $= R_{mf_e}$ (from Fig. 3-6).

$$K = 60 + 0.133 \times T_f$$

$$= 60 + 0.133 \times 161$$

$$= 81.41$$

$$\log R_{we} = \left(\frac{SSP + K\log R_{mf_e}}{K}\right)$$

$$= \left[\frac{-70 + (81.41)\log(1.10)}{(81.41)}\right]$$

$$= -0.815$$

$$R_{we} = 0.152$$

Since $R_{we} > 0.10$, $R_w = R_{we} = 0.152$ ohm-m

Example 3-4.[3] Calculate R_w from the SP and resistivity log shown in Figure 3-11. Other pertinent data from the log heading are as follows:

Formation: Morrow Sand

R_{mf} @$70°F = 2.0$ ohm-m $TD = 10{,}500$ ft

R_m @$70°F = 2.5$ ohm-m $SP = -70$ mv (Fig. 3-11)

$T_{ms} = 60°F$ $R_t = 65$ ohm-m (Fig. 3-11)

$T_{BH} = 164°F$ $h = 24$ ft

Solution:

$$T_f = \left(\frac{T_{BH} - T_{ms}}{TD}\right) \times D_f + T_{ms}$$

$$= \left(\frac{164 - 60}{10{,}500}\right) \times 8{,}126 + 60 = 140°F$$

Correct R_m and R_{mf} to formation temperature using Figure 3-6.

R_{mf} @$140°F = 1.0$ ohm-m

R_m @$140°F = 1.3$ ohm-m

Correct SP to SSP using Figure 3-9.

$R_i/R_m = 65/1.3 = 50$

correction factor from Figure 3-9 = 1.07

R_i จาก Short Normal

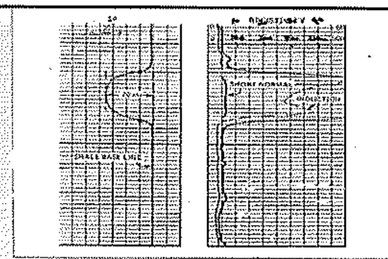


Figure 3-11. SP and resistivity log for Example 3-4 (courtesy of Atlas Wireline Services).

$SSP = 1.07 \times SP$

$= 1.07 \times 70 = -75$ mv

$K = 60 + 0.133 \times T_f$

$= 60 + 0.133 \times 140 = 78.62$

$\log R_{we} = \left[\frac{-75 + (78.62)\log(1.0)}{78.62}\right]$

$R_{we} = 0.111$

Since $R_{we} > 0.10$, therefore, $R_w = R_{we} = 0.111$ ohm-m

นักศึกษาจะใช้อัน Fig. ก็ได้ หรือ สูตร R_w ก็ได้

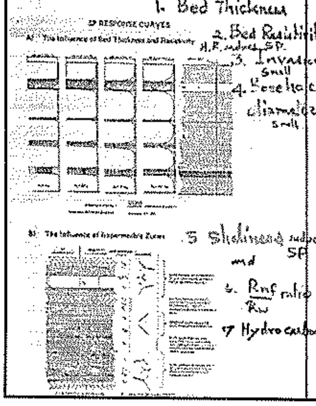
SP is influenced by

1. Bed thickness
2. Bed Resistivity (H.R. reduces SP)
3. Invasion (small)
4. Borehole diameter (small)
5. Shaliness reduces SP and
6. $\frac{R_{mf}}{R_w}$ ratio
7. Hydrocarbon

SP RESPONSE CURVES

A) The Influence of Bed Thickness and Resistivity

B) The Influence of Impermeable Zones



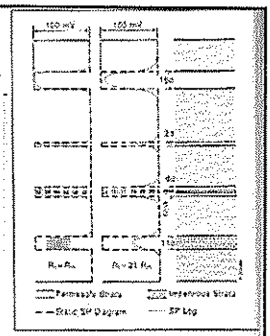
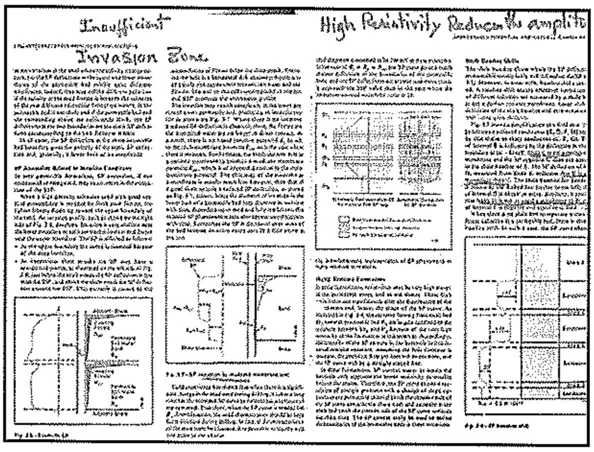


Fig. 3.3—SP curve in beds of different thickness for $R_t = R_m$ (left) and $R_t = 21 R_m$ (center).

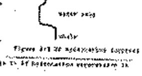
Insufficient Invasion Zone

High Resistivity Reduce the amplitude



Shale Influence

7 Hydrocarbon suppression



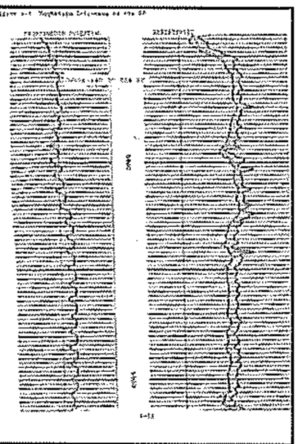
8 Shale Baseline Shifts

Miscellaneous Factors Influencing the SP

9 Magnetism

10 Bimetallic Effects

SP & Sonic



...and charge transport is entirely the result of the Na^+ ion. Such a membrane is called a perfect membrane. The maximum possible shale potential occurs across a perfect membrane because $t_{Cl}=0$ and $t_{Na}=1$, and according to the Nernst equation,

$$E_m=(RT_K/F)\ln(a_1/a_2). \quad (6.5)$$

When a shale membrane is imperfect, a Cl^- anion leak occurs and the membrane potential decreases. In this case, a correction factor should be introduced into Eq. 6.5.

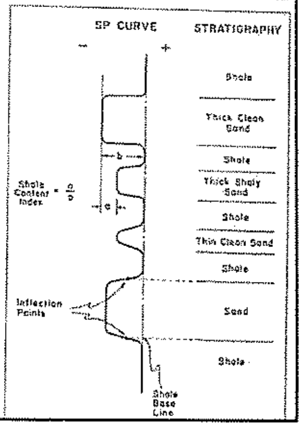
6.3.3 Electrochemical Component of the SP. The two situations illustrated in Figs. 6.5 and 6.6 can be combined into one cylindrical cell. Fig. 6.7 shows a cylindrical trough that contains two solutions of sodium chloride of activities a_1 and a_2. The two solutions are separated at the upper part of the trough by a perfect shale membrane and at the lower part of the trough by a clean porous medium. As illustrated, an electric current will flow across the shale from the concentrated solution to the dilute solution, creating the membrane potential, E_m. The electric current will flow across the clean porous medium from the dilute solution to the concentrated solution, creating a diffusion potential, E_d. This configuration, first suggested by Mounce and Rust,[5] constitutes a closed electric circuit in which E_d and E_m are created electrochemically. These two potentials are additive, and their sum is known as the electrochemical potential, E_c:

$$E_c=E_d+E_m. \quad (6.6)$$

Using the expression of E_d and E_m given by Eqs. 6.4 and 6.5 yields

$$E_c=-2t_{Cl}(RT_K/F)\ln(a_1/a_2). \quad (6.7)$$

Fig. 6.7 shows that the components forming the closed electric circuit are found at the boundary between a shale bed and a water-bearing permeable formation traversed by a borehole filled with drilling mud. The saltwater-bearing formation plays the roles of both a concentrated NaCl solution of activity a_w and a clean porous membrane. The shale is, of course, the ion-selective...



...permeable formation traversed by a borehole filled with drilling mud. The saltwater-bearing formation plays the roles of both a concentrated NaCl solution of activity a_w and a clean porous membrane. The shale is, of course, the ion-selective membrane. The drilling mud in the borehole and the mud filtrate in the permeable invaded zone constitute the dilute solution of activity, a_{mf}.

Upon substitution of a_w and a_{mf} for a_1 and a_2, respectively, and conversion of the natural logarithm to the logarithm of the base 10, Eq. 6.7 becomes

$$E_c=-K\log(a_w/a_{mf}), \quad (6.8)$$

where $K=2(2.303)t_{Cl}RT/F=4.606\,t_{Cl}RT_K/F$. $\quad (6.9)$

At 25°C, the chloride and sodium mobilities are 7.91×10^{-4} and 5.19×10^{-4} cm/s-V, respectively. According to Eq. 6.2,

$$t_{Cl}=\frac{7.91\times10^{-4}}{(7.91+5.19)\times10^{-4}}=0.604.$$

The transference number of the chloride ion, t_{Cl}, is relatively independent of concentration and temperature over the ranges normally experienced in well-logging applications.[4] Substituting 0.604 for t_{Cl} in Eq. 6.9, together with the values of the gas and Faraday constants, results in

$$K=4.606(0.604)(8.314/96,510)T_K=0.00024T_K.$$

Expressing K in millivolts and temperature in degrees Celsius gives

$$K=0.24(273.2+T)$$

$$K=65.5+0.24T. \quad (6.10)$$

If temperature, T, is expressed in degrees Fahrenheit,

$$K=61.3+0.133T. \quad (6.11)$$

6.3.4 Electrokinetic Component of the SP. Mud filtrate may be forced into the drilled formations as a result of the difference between formation pressure and the hydrostatic pressure of the mud column. This filtration process results in an electrokinetic potential,

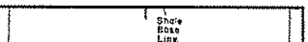


Fig. 6.3—Schematic of an SP curve recorded in a shale/sand formation sequence.

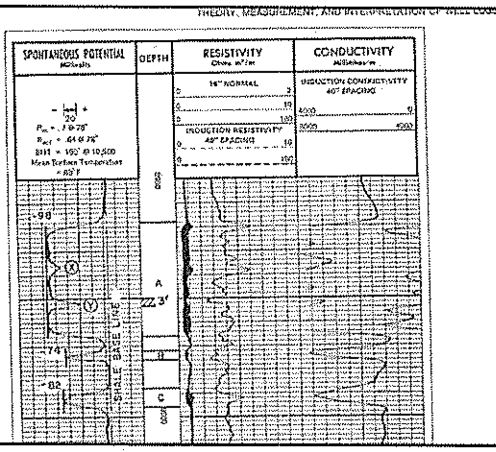
also known as the streaming potential, E_k. A mudcake is usually formed across permeable formations. The mudcake contains clay particles that have an electric double layer. Because of the difference in ionic concentration between the bound clay water and the free water, a potential difference exists. This difference between the free water and the boundary of the bound-water layer is known as the zeta potential, ξ. If pressure is applied to the solution, the solution will flow past the solid surface, carrying with it charges that have a potential ξ. The movement of these charges creates the electrokinetic potential. Wyllie's[6] experimental investigations of the electrokinetic potential developed across a mudcake established a relationship of the form

$$E_k=xp^y, \quad (6.12)$$

where E_k = electrokinetic potential, p = differential pressure, and x and y = constants related to mud composition and resistivity.

The greater the mud resistivity and the pressure differential are, the greater the electrokinetic potential is. Experimental data for 1,000-psi differential pressure are represented by the upper curve in Fig. 6.8.

Shale is similar, in kind and properties, to a well-formed mudcake. Gondouin and Scala[7] experimentally proved the existence of electrokinetic potential across shales. Their data are represented by the lower curve in Fig. 6.8. Because the SP is a relative measurement with respect to shale, the combined contribution of potentials of electrokinetic origin would be the difference between the electrokinetic potential across the shale and that across the mudcake. At low mud resistivity and low differential pressure, this difference is generally small, as shown by Fig. 6.8. These differences may vary considerably in practice, however, depending on the relative...



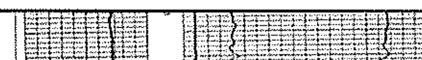


Fig. 6.4—Electric log of Example 6.1 (courtesy Atlas Wireline Services).

Experience indicates that electrokinetic potentials are generally negligible for low mud resistivities and 500-psi or less differential pressure.[8]

Electrokinetic potentials are usually ignored in SP calculations. The total naturally occurring electric potential, called the static self-potential, E_{SSP}, is assumed to equal E_c and is expressed with Eqs. 6.6 and 6.8:

$$E_{SSP}=E_c=E_d+E_m=-K\log(a_w/a_{mf}). \quad (6.13)$$

The negative sign is added because, by convention, a negative SP is measured relative to the shale when $a_w>a_{mf}$.

6.4 Theoretical E_{SSP} vs. Measured SP

The theoretical potential, E_{SSP}, expressed by Eq. 6.13 is determined by the formation temperature, which controls the value of K, and the chemical activities. The formation temperature can be determined as discussed in Chap. 4. The mud filtrate is sampled and its properties are measured. Consequently, if E_{SSP} can be deduced from the measured SP, Eq. 6.13 can be solved for formation water properties. As the equivalent circuit of Fig. 6.9 shows, the current, I, circulating at the sand/shale boundary is generated by the total potential:

$$E_{SSP}=I(r_f+r_{sh}+r_m), \quad (6.14)$$

where r_f, r_{sh}, and r_m are the resistances encountered by the electric current while flowing through the sand formation, shale formation, and mud column, respectively. The measured SP is the ohmic potential drop as the electric passes from shale to sand. It is expressed by

$$E_{SP}=Ir_m \quad (6.15)$$

Combining Eqs. 6.14 and 6.15 yields

$$E_{SP}=\frac{r_m}{r_f+r_{sh}+r_m}E_{SSP}. \quad (6.16)$$

Eq. 6.16 indicates that E_{SSP} is greater than E_{SP}. The E_{SSP}/E_{SP} ratio depends on the borehole's resistivities and geometry, as well as the shale and sand formations. Formation resistivity is typically greater than mud resistivity. However, the current has a much wider cross-sectional path in the formation, resulting in a low resistance compared with that of the restricted path in the borehole. r_m can be expressed as

$$r_m=(R_m/d_h^2)h, \quad (6.17)$$

where R_m = mud resistivity, h = bed thickness, and d_h = borehole diameter.

We can see from Eq. 6.17 that, for relatively low-resistivity formations, freshwater-based mud, thick beds, and small boreholes it is practical to assume that $E_{SP}\approx E_{SSP}$ because $r_m\gg(r_f+r_{sh})$.

To account for the difference between E_{SP} and E_{SSP}, an empirical correction chart (Fig. 6.10) was constructed from data taken...

...because $(R_w)_{eq}>0.1$.

$R_w=(R_w)_{eq}=0.167$ Ω·m at 105°F.

Fig. 6.19 attempts to take the nonideal shale-membrane behavior into consideration:

$R_{mf}/R_{mf}=0.9/0.89\approx1$ Ω·m.

$R_{mf}/R_w=10.8$.

$R_w=0.89/10.8=0.082$ Ω·m at 105°F.

The concept of the shale-membrane efficiency results in

$$m_{sf}=0.47+0.3(0.9)$$
$$=0.74. \quad (6.23)$$

From Figs. 6.23 and 6.24, $R_w=0.088$ Ω·m for $m_{sf}=0.8$ and $R_w=0.051$ Ω·m for $m_{sf}=0.7$. By interpolation, $R_w=0.067$ Ω·m for $m_{sf}=0.74$.

The R_w values obtained by these different methods are listed in Table 6.1, together with deviation and possible error in S_w determination. As Table 6.1 shows, the values obtained when the nonideal shale behavior is taken into consideration are in closer agreement with that obtained from chemical analysis and result in a lower error in S_w value.

6.6 Character and Shape of the SP Deflection

In clean formations, the deflection of the SP curve off the shale baseline is expressed by Eq. 6.21. Considering a relatively short interval of a few hundred feet of a wellbore, the temperature and, consequently, K and R_{mf} remain practically unchanged. $(R_w)_{eq}$ is directly proportional to R_w. Therefore, the higher R_w is, the lower the SP deflection is; i.e., the higher the formation water salinity is, the higher the SP deflection is.

In addition to the absolute value of R_w, the contrast R_{mf}/R_w or precisely $R_{mf}/(R_w)_{eq}$ determines the magnitude of SP deflection. The contrast between mud filtrate and formation water salinity...

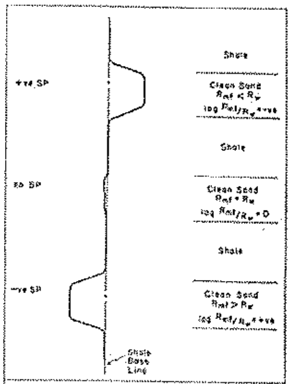


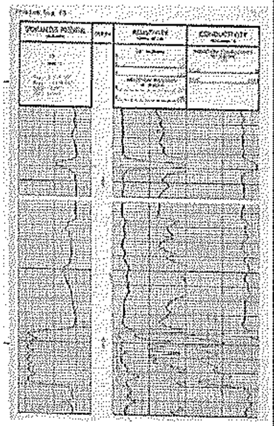
Fig. 6.25—Schematic of the effect of contrast between R_{mf} to R_w on SP deflection.

HW NO 4 SP-LOG

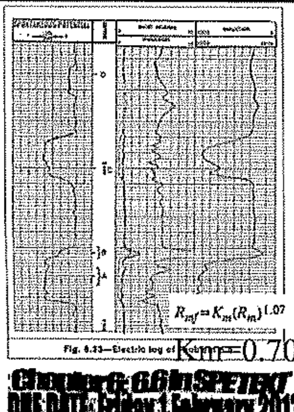
Chapter 4; 1 and 3 in HILCHIE

4. From an induction electric log the following data are obtained, SP is -10 mV, ... The well is in Alberta. The bed is 5 feet thick. What is the Rw from the SP.

5. Determine the Rw from the SP for the permeable zones ... on the next page. If the Rw's differ explain the reason why. This is a Gulf Coast well.



and Chapter 6; 6.6 in SPE TEXT



$R_{mf} = K_m (R_m)^{1.07}$

Fig. 6.33—Electric log of

Kmr=0.708

Problems

6.1 Calculate the relative magnitude of the membrane potential compared with the diffusion potential for clean sands at 80°F.

6.2 a. Estimate E_{SSP}, assuming that the shale membrane is perfect, if formation temperature = 200°F, R_{mf} at 200°F = 0.5 Ω·m, and R_w at 200°F = 0.1 Ω·m.

b. Taking into consideration the nonideality of the shale membrane, estimate E_{SSP} if R_{sh} = 2 Ω·m.

6.3 Estimate E_{SSP} for a formation with the following characteristics.

Formation temperature, °F	90
Formation thickness, ft	100
R_{mf}, Ω·m at 90°F	2

Problem 6.6 0.04 Ω·m, 90,000 ppm.

b. Take into account the fact that water is fresh, so the effect of salts other than NaCl has to be considered.

6.4 The electric log in Fig. 6.31 was obtained in a well drilled with freshwater-based mud where R_{mf} = 0.65 at 85°F. Maximum temperature recorded in the well was 165°F at 8,700 ft. If Zone 1 is a clean water-bearing sand and formation water salinity is practically the same in all sands, determine R_w and I_{sh} of the different permeable zones.

6.5 Determine the formation water salinity of the formations discussed in Example 6.7.

6.6 The heading of the electric log in Fig. 6.33 lists the following information.

Total depth, ft	9,500
Maximum recorded temperature, °F	168
R_m, Ω·m at 168°F	0.56
Mud weight, lbm/gal	11

a. Estimate the formation water resistivity and salinity for the bottom permeable Zone A.

b. Explain the reduction of SP deflection displayed in Level B.

c. Explain the reduction of SP deflection displayed at Level C.

d. Explain the reduction of the SP deflection at Level D.

Chapter 6; 6.6 in SPE TEXT

DUE DATE; Friday 1 February 2013

TABLE 4.1—K_m VALUES AS A FUNCTION OF MUD WEIGHT

Mud Weight (lbm/gal)	Mud Weight (kg/m³)	K_m
10	1200	0.847
11	1320	0.708
12	1440	0.584
13	1560	0.488
14	1680	0.412
16	1920	0.380
18	2160	0.350

because the manner in which the mudcake is packed in the cell dictates the resistivity value indicated by the meter.

4.3.7 Correlation of Mud-Filtrate and Mudcake Resistivities to Mud Resistivity. In early practice, only the drilling-mud resistivity was measured. Even in present practice, some mud logging units measure R_m only periodically. Also, values of R_m are provided by some measurement-while-drilling (MWD) systems.[3] In this case, R_{mf} is estimated from empirical correlation to R_m. Because of the difficulty associated with measuring R_{mc}, even if a measured value is available, it is usually estimated through empirical correlations.

The following empirical equation was derived from data taken from 94 field muds[5]:

$$R_{mf} = K_m (R_m)^{1.07}, \qquad (4.1)$$

where K_m is a coefficient that varies with mud weight. Table 4.1 gives K_m values as a function of mud weight. It was also found that[5]

$$R_{mc} = 0.69 R_{mf} (R_m / R_{mf})^{2.65}. \qquad (4.2)$$

Eqs. 4.1 and 4.2 are presented graphically in Fig. 4.14. The use of the correlation in Eq. 4.1 was restricted to nonlignosulfate muds, which were not used at the time that the correlation was developed. A recent study[7] shows that the use of the correlation can be expanded to today's widely used lignosulfonate muds. The same study also proposed the following correlation for all types of freshwater muds:

$$\log(R_{mf}/R_m) = 0.396 - 0.0475\rho_m, \qquad (4.3)$$

where ρ_m is the mud density in lbm/gal.

Other statistical correlations that are valid only for low-weight predominantly sodium chloride (NaCl) muds are[9]

$$R_{mf} = 0.75 R_m \qquad (4.4)$$

and $R_{mc} = 1.5 R_m$. (4.5)

Empirical correlations for specific mud types—such as lime, gypsum, and calcium lignite/calcium lignosulfonate muds—are available in Ref. 10.

4.3.8 Effect of Temperature on Mud, Mud-Filtrate, and Mudcake Resistivities. The mud, mud-filtrate, and mudcake resistivities are usually measured at surface temperature. Quantitative interpretation of electric logs requires representative values of R_m, R_{mf}, and R_{mc} under borehole conditions.

As in the case of rocks, the conductivity of the mud results mainly from the liquid phase. Drilling mud's conductivity and that of its filtrate and cake increase with temperature. For predominantly NaCl muds, the nomograph of Fig. 1.7 or Eq. 1.11 can be used to convert surface resistivity values to borehole values. Fig. 4.15 graphically presents NaCl solution resistivity vs. temperature. Salinity obtained from Fig. 1.7 or 4.15 is approximate and not true salinity because the graphs are for solids-free NaCl solutions.

Several studies[10,11] showed that the effect of temperature on field drilling muds is not the same as NaCl solution. Over the temperature range of 75 to 225°F, the difference may be as much as 10% for R_m and R_{mf} and 25% for R_{mc}. If a certain ionic conten

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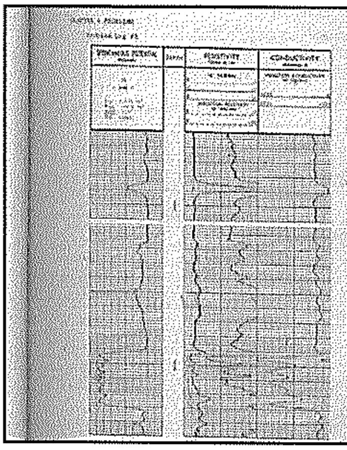


350

Problem 2.19	A=0.45 cm, σ=37 barns.
Problem 2.20	Σ=22.2 c.u.
Problem 2.23	b. Σ_w=59.7 c.u.
Problem 2.25	a. I=532 photons/s·cm². b. I=360 photons/s·cm². c. I=926 photons/s·cm².
Problem 2.26	12.5%.
Problem 2.27	a. C_d=0.035 day⁻¹ and 4×10⁻⁷s⁻¹. b. 25 mCuries, 1.52×10⁻⁴ mCuries. c. 4.6×10¹⁹ atoms, 14×10⁹ atoms.
Problem 2.33	E=2.6 MeV.
Problem 2.34	a. I=224 photons/s·cm². b. μ=0.227 cm⁻¹. c. I=193 photons/s·cm².
Problem 2.35	a. 6.64×10²² atoms/cm³. b. 6.81×10²² atoms/cm³. c. 1.49×10²¹ atoms/cm³.

Chapter 3

Problem 3.2	a. α_{pe}=14.9°. b. α_{se}=26.6°.
Problem 3.4	Δt_p=384.7 μs, Δt_s=620.9 μs.
Problem 3.5	v_p=2,365.3 m/s, v_s=1,014.5 m/s.

Chapter 4

Problem 4.2	a. 8.3 in, 12.5 in. b. ≈0.4 in. c. different types of clay minerals.
Problem 4.4	c. T=70e...
Problem 4.5	a. 3,000 ppm. b. R_m=0.08 Ω·m. c. R_{mf}=1.33 Ω·m at 90°F, R_{mf}=0.59 Ω·m at 180°F. e. R_{mc}=0.66 Ω·m at 180°F.
Problem 4.6	T_f=180°F, R_m=0.18 Ω·m, R_{mf}=0.06 Ω·m, R_{mc}=0.76 Ω·m.
Problem 4.7	b. T_s=90°F, m_f=6.8×10⁻⁵ ft⁻¹. c. T_f=460°F.
Problem 4.8	a. ≈3,250 ppm.

Problem 5.14	a. h_{mc}=0.5 in., $(R_t)_{ILd}$=65 Ω·m. b. $(R_t)_{ILd}$=65 Ω·m. c. R_{xo}=35 Ω·m. d. R_{xo}=64 Ω·m.
Problem 5.15	a. 9.5 and 0.25 Ω·m. b. Yes. c. R_{xo}=0.8 Ω·m. d. h=9 ft. e. 9.5 and 0.28 Ω·m.
Problem 5.16	Zone D: d_i=64 in., R_{xo}=29 Ω·m, R_t=5 Ω·m. Zone E: d_i=40 in., R_{xo}=11.5 Ω·m, R_t=2.5 Ω·m.
Problem 5.17	a. 45 and 45 Ω·m. b. No invasion; R_{xo}=R_t=45 Ω·m. c. 4.6 and 8 Ω·m. f. R_{xo}=10 Ω·m, R_t=0.33 Ω·m. g. R_{xo}=14 Ω·m, R_t=0.94 Ω·m.
Problem 5.18	a. R_i=24 Ω·m. b. R_a=21 Ω·m. c. R_t=3.7 Ω·m. d. R_t=24 Ω·m. e. R_{xo}=2 Ω·m. f. G=0.35. g. R_t=35 Ω·m. h. S_w=25%. i. S_w=70%.

Chapter 6

Problem 6.1	E_d/E_m=4.6.
Problem 6.2	a. SSP=−60 mV. b. SSP=−28 mV.
Problem 6.3	a. SSP=+16 mV. b. SSP=−32 mV.
Problem 6.4	R_w=0.03 Ω·m.
Problem 6.5	90,000 ppm.
Problem 6.6	0.01 Ω·m, 90,000 ppm.

Chapter 7

Problem 4.6	T_f=180°F, R_m=0.18 Ω·m, R_{mf}=0.06 Ω·m, R_{mc}=0.76 Ω·m.
Problem 4.7	b. T_s=90°F, m_f=6.8×10⁻⁵ ft⁻¹. c. T_f=460°F.
Problem 4.8	a. ≈3,250 ppm. b. 2,681 ft above sea level. c. T_f=133°F at 5,850 ft. d. g_G=1.08°F/100 ft. e. T_f=131°F, R_m=1.17 Ω·m, R_{mf}=1.01 Ω·m, R_{mc}=1.05 Ω·m.
Problem 4.9	T_f=116°F.

Chapter 5

Problem 5.1	0.1%.
Problem 5.3	c. R_{SN}=4.8 Ω·m, R_{LN}=3.9 Ω·m. d. Zone D is shale. e. R_{SN}=3.8 Ω·m, R_L=5.1 Ω·m, R_L>R_{SN} because Zone B is relatively thin.
Problem 5.4	a. 88 ft.
Problem 5.5	50 Ω·m (from the Lateral's plateau).
Problem 5.6	a. 2.937 V. b. R_a=30 Ω·m. c. R_a=30 Ω·m. d. 0.225 V, 10 Ω·m, 10 Ω·m. e. Yes.
Problem 5.7	0.1 to 50 Ω·m.
Problem 5.8	2 in.
Problem 5.9	2, 68, 44, and 2 Ω·m.
Problem 5.10	54 and 68 Ω·m.
Problem 5.11	a. 24, 18, and 15 Ω·m. b. 39, 34, and 24 Ω·m.
Problem 5.12	2.3 and 2 Ω·m.
Problem 5.13	a. R_{LL}=8 Ω·m. b. φ=28%. c. R_{xo}=9.5 Ω·m. d. R_{xo}=9.5 Ω·m. e. The Short Normal is affected by R_i.

Problem 6.5	90,000 ppm.
Problem 6.6	0.04 Ω·m, 90,000 ppm.

Chapter 7

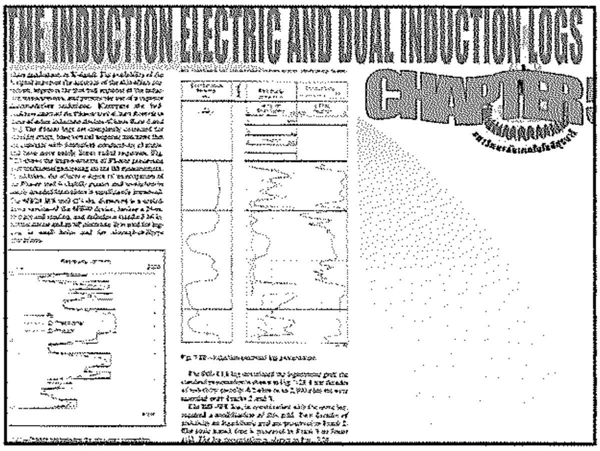
Problem 7.1	t=3rc.
Problem 7.3	c. Zone 1; the relatively high resistivity of the re... suppressed the response of the SP ...
Problem 7.4	80 API units.
Problem 7.6	Yes; the upper sand is responsible for the high pr... duced WOR. Water flow is indicated by the re... tively high response of the uranium curve.
Problem 7.7	The high radioactivity of Zone A is caused by high uranium content. An average shale index 35% is estimated from the thorium curve.

Chapter 8

Problem 8.2	$(\rho_{ma})_{A}$=2.608 g/cm³, $(\rho_{ma})_{M}$=1.714 g/c...
Problem 8.5	C=1.0078.
Problem 8.6	Zone X: limestone; ϕ_{avg}=2%. Zone Y: sandstone; ϕ_{avg}=15%.
Problem 8.7	S_g=60% in the bottom part of the formation
Problem 8.8	a. Not representative because of irregular b... hole enlargement. b. φ=33%. c. φ=30%; shale effect.

Chapter 9

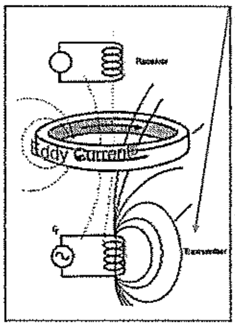
Problem 9.8	a. +3.8%.
Problem 9.9	+3%.
Problem 9.11	a. Gas/oil contact at 9,030 ft. Oil/water contact at 9,034 ft. b. The gas and oil saturation is approximat... 95%.
Problem 9.12	a. The oil/water contact is at 6,480 ft. b. φ=25%, S_w=50%.



INDUCTION LOGGING THEORY

Induction tools measure formation conductivity by inducing a current flow within the formation

INDUCTION PRINCIPLES

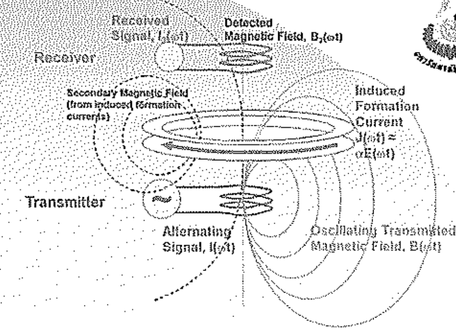


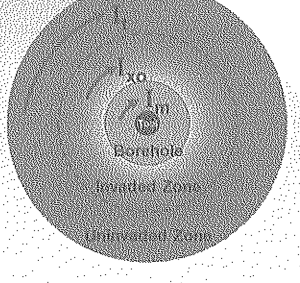
A transmitter coil, with an alternating current passing through it, sets up an alternating magnetic field. "Faraday's law" predicts this time-varying field will establish an emf in the formation.

The emf causes eddy currents to flow in circular paths around the tool (coaxial with the borehole) in areas of formation known as "ground loops." The eddy currents are 90° out of phase with the transmitter currents. Their magnitude depends on the surrounding formation's conductivity.

"Ampere's law" predicts that these eddy currents will produce their own magnetic fields. These fields cut through the receiver coil and induce an alternating voltage at the receiver that is proportional to the strength of the secondary magnetic field and therefore related to formation conductivity.

Induction Principles





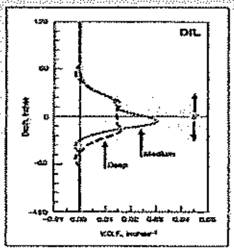
When to Run Induction

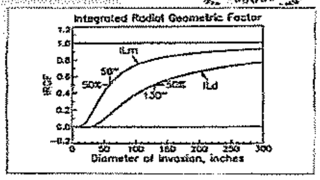
	High Water Resistivity, R_w	Medium Water Resistivity, R_w	Low Water Resistivity, R_w
High Mud Resistivity, R_m	Normally OK for induction logs, if porosity > 8% otherwise R_t may be too high (over 250 Ω-m)	Perfect for induction logging	Perfect for induction logging
Medium Mud Resistivity, R_m	Normally OK for induction logs if porosity > 10%	Perfect for induction logging	Perfect for induction logging
Low Mud Resistivity, R_m	Not advised. Borehole signal will often be larger than formation signal		Acceptable for induction logging if porosity > 6% and hole diameter < 10 inches, otherwise borehole signal may overwhelm formation signal

GEOMETRICAL FACTOR

Vertical

Radial





ADVANTAGES OF MULTICOIL SONDES

- Improvement of vertical resolution by suppression of the shoulder bed response
- Improvement of the investigational depth by suppression of the borehole fluid response
- Minimization of the direct coupling X-signal contribution

DUAL INDUCTION TOOL

VERTICAL RESOLUTION

DEEP --- 5 FEET

6FF40 *MEDIUM---- 4.5 FEET*

SHORT GUARD --- 12 INCHES

DEPTH OF INVESTIGATION

DEEP ---- 5.4 FEET

MEDIUM --- 2.5 FEET

SHORT GUARD ---- 15 INCHES

HIGH RESOLUTION INDUCTION TOOL

VERTICAL RESOLUTION

HRI *DEEP --- 1 FEET*

HRAI *MEDIUM---- 1 FEET*

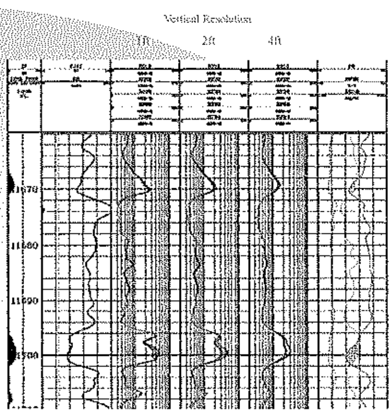
ARCt *Shallow --- < 17 INCHES*

DEPTH OF INVESTIGATION

DEEP ---- 7.58 FEET

AIT *MEDIUM --- 3.25 FEET*

Shallow ---17 INCHES



DEEP INDUCTION AND R_T

In 90% of the cases, it is permissible to assume that the deep induction reading is equal to R_t. Conditions where this assumption is not valid include:

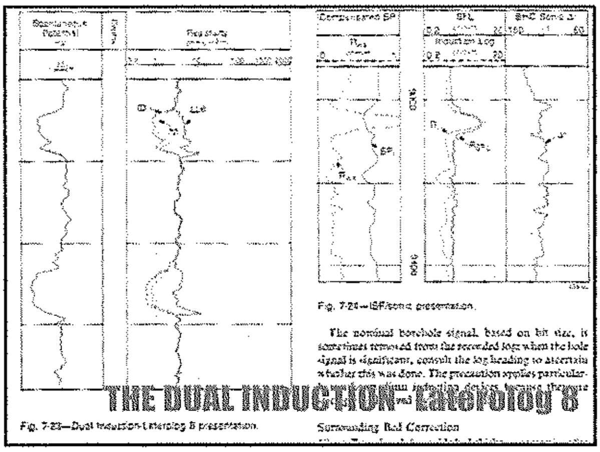
Induction logs run in very large holes

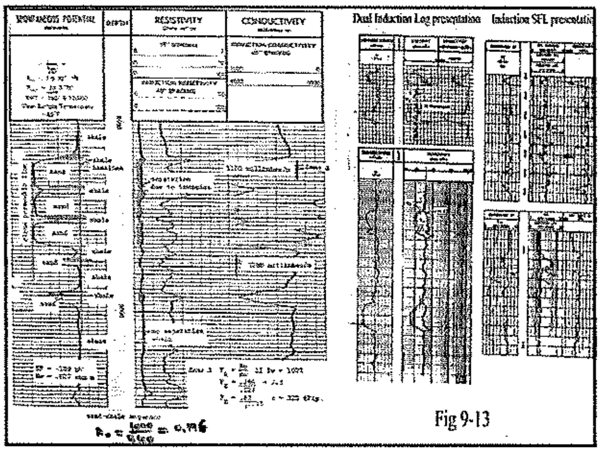
Induction logs run in salt muds

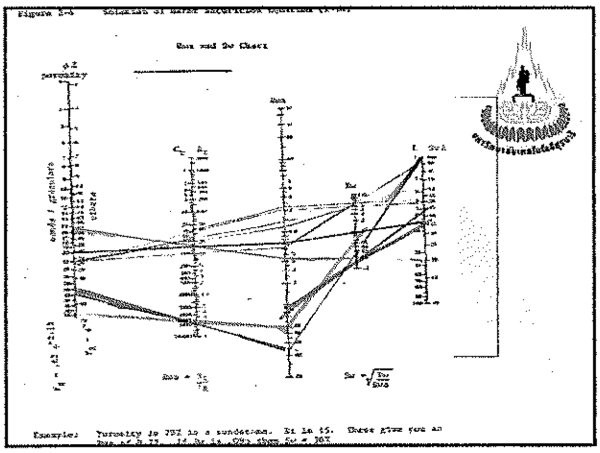
Places where the bed of interest is thin

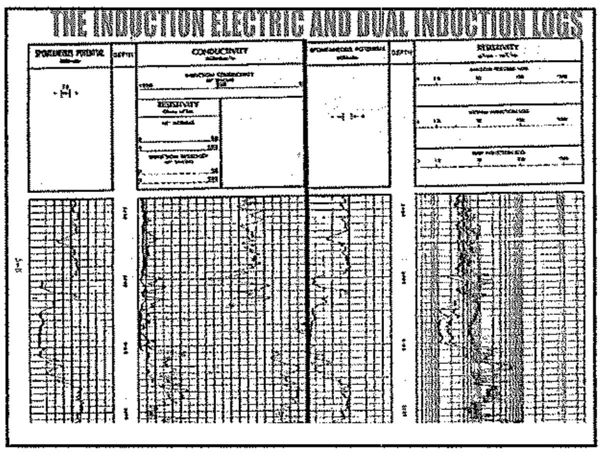
Where the shoulder-bed resistivity is markedly different from the resistivity of the bed under consideration

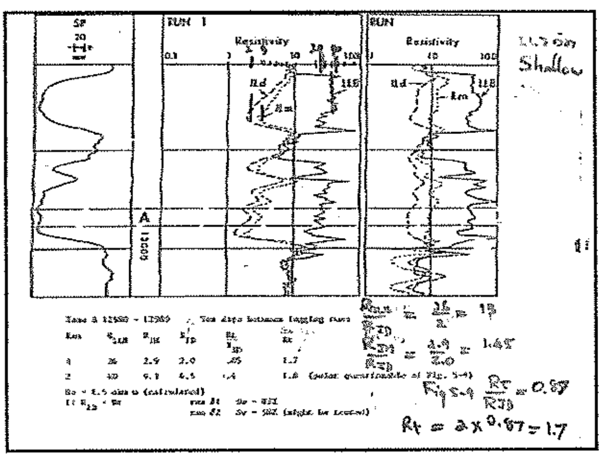
Where invasion is abnormally deep

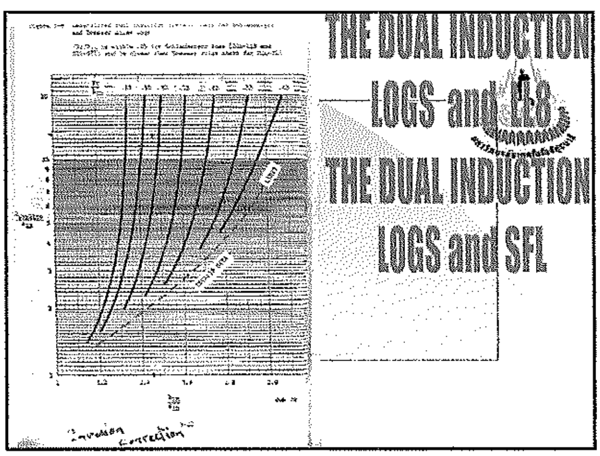

THE DUAL INDUCTION- Laterolog 8
Fig. 7-23—Dual Induction-Laterolog 8 presentation.
Fig. 7-24—ISF/sonic presentation.
Surrounding Bed Correction

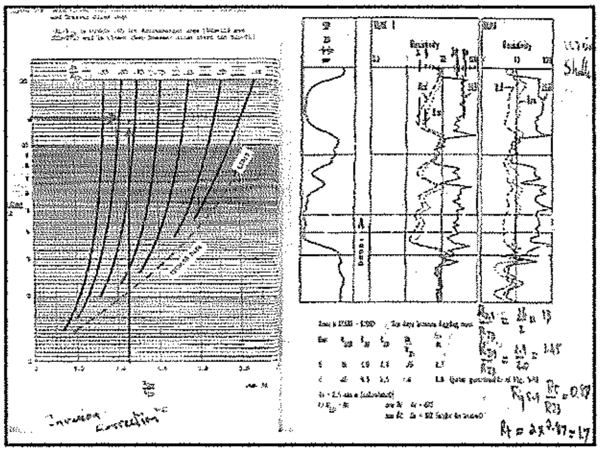

SPONTANEOUS POTENTIAL
DEPTH
RESISTIVITY
CONDUCTIVITY
Dual Induction Log presentation
Fig 9-13

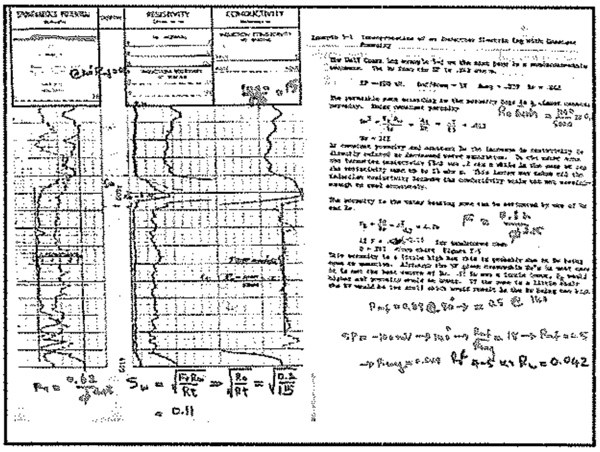

Rwa and Sw Chart

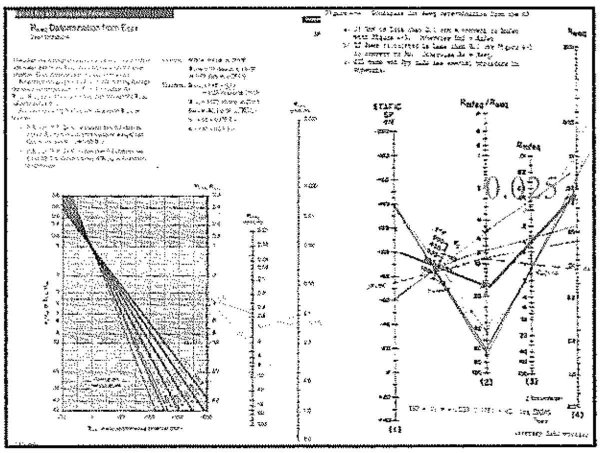

THE INDUCTION ELECTRIC AND DUAL INDUCTION LOGS
SPONTANEOUS POTENTIAL
DEPTH
CONDUCTIVITY
RESISTIVITY

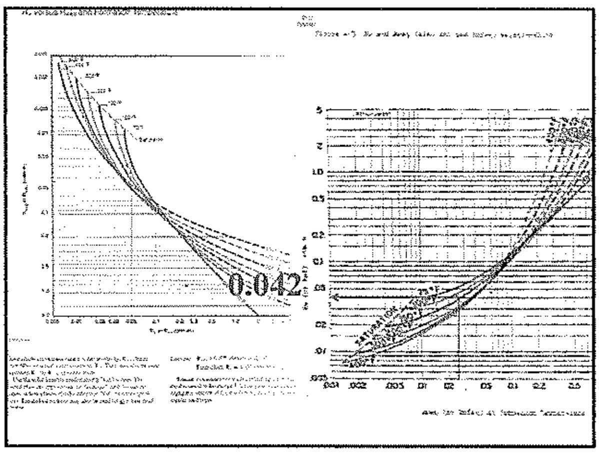

SP
RUN 1
Resistivity
RUN
Shallow
A
Rt = 2x0.87 = 1.7

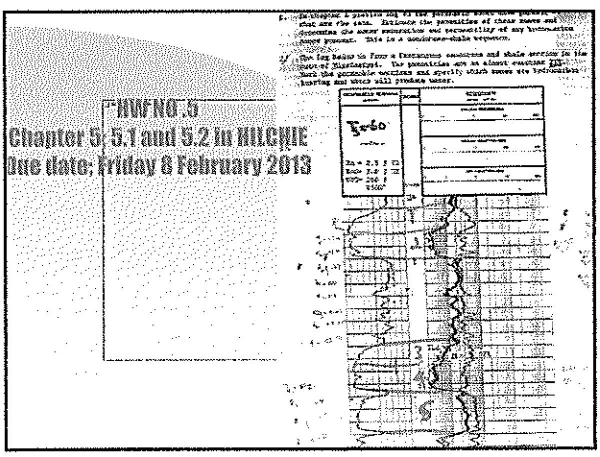

THE DUAL INDUCTION
LOGS and LL8
THE DUAL INDUCTION
LOGS and SFL
Invasion Correction

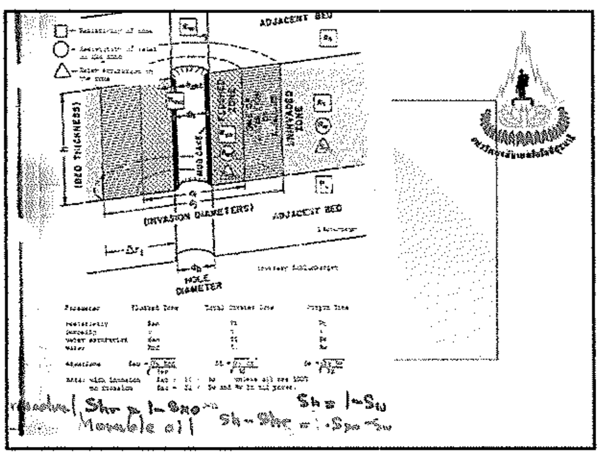





0.025


0.042


HWNO.5
Chapter 5: 5.1 and 5.2 in HILCHIE
Due date; Friday 8 February 2013


ADJACENT BED
MUD CAKE
(INVASION DIAMETERS)
HOLE DIAMETER
Shr = 1-Sxo
Sh = 1-Sw
Movable oil Sh - Shr = Sxo - Sw

Natural gamma ray overview

- Designed to measure naturally occurring gamma radiation emitted by a formation
- Principle: gamma rays are produced by radioactive decay of potassium, uranium, and thorium, which occur in variable amounts in all formations
- Measurements:
  gamma ray API (GAPI)
- Primary objectives:
  lithology determination
  volume of shale determination

1

THE GAMMA RAY TOOLS

THE GAMMA RAY IS NOT A POROSITY TOOL - HOWEVER, IT IS USU RUN IN COMBINATION WITH POROSITY TOOLS AND IT IS VERY HEL IN INTERPRETING POROSITY MEASUREMENTS.

I. PRINCIPLE:

THE GAMMA RAY TOOL MEASURES THE NATURAL RADIOACTIVITY OF THE FORMATIONS. RADIOACTIVE ELEMENTS LIKE POTASSI TEND TO CONCENTRATE IN SHALES. THESE ELEMENTS EMIT NATURAL GAMMA RAYS WHICH CAN BE EASILY MEASURED BY MEANS OF A GEIGER MULLER COUNTER OR A SCINTILLATION DETECTOR. GEIGER COUNTER

ON THE OTHER HAND, CLEAN RESERVOIR FORMATIONS LIKE SANDSTONE, DOLOMITE OR LIMESTONE USUALLY HAVE A VERY LOW LEVEL OF NATURAL RADIOACTIVITY.

BY RECORDING THE NUMBER OF GAMMA RAYS EMITTED BY THE FORMATION THE GAMMA RAY TOOL THEREFORE ALLOWS EASY DISTINCTION BETWEEN CLEAN RESERVOIR ROCKS AND SHALES.

FURTHERMORE, IF A SMALL QUANTITY OF SHALE IS PRESENT IN THE RESERVOIR ROCK, THE NUMBER OF GAMMA RAYS MEASURED ALLOWS A QUANTITATIVE EVALUATION OF THE PERCENTAGE OF SHALE CONTAINED IN THE FORMATION.

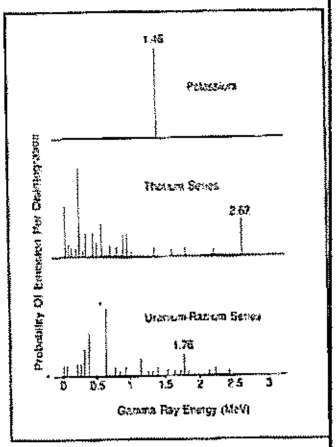


Fig. 3-8—Gamma ray emission spectra of radioactive minerals.

Natural gamma ray applications

- Lithology determination (simple vs. complex)
- Estimate volume of shale (V_{sh})
- Well-to-well correlation
- Formation boundaries (bed thickness)
- Depth control (run-to-run correlation)

Natural gamma ray operating environment

- The natural gamma ray is capable of acquiring accurate data in:
  - Fresh water-based mud
    Salt water-based mud
    Oil-based mud
    Air-drilled boreholes
  - Cased hole

Physics of the measurement

- Relates to radioactive decay of potassium, uranium, and thorium
- K, U, Th exist in variable quantities in all formations
  - Orthoclase $KAlSi_3O_8$
  - Montmorillonite $KAl_4(Si_4O_{10})(OH)_8$
- Emit gamma rays as part of the decay process
- Tool measures ("counts") number of gamma rays emitted

What is a gamma ray?

- High-energy electromagnetic radiation
- Emitted from the nucleus of an atom
- Photons: no mass and no charge (pure energy)
- Can be thought of as particles or waves
- Travel at speed of light

What is a gamma ray?

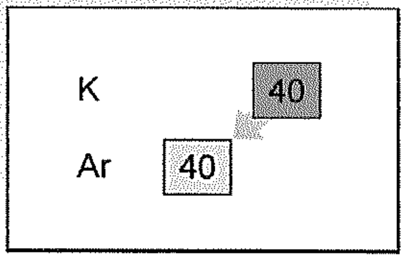
Radiation Type	Energy Level
Gamma Rays	1 Gev 1 Mev
X-Rays	1 KeV
Ultraviolet Rays	
Visible Light	
Infrared	1 eV
Short Radio Waves	10^{-3} eV 10^{-6} eV
Broadcast Radio Waves	
Long Radio Waves	10^{-9} eV 10^{-12} eV

The source of gamma rays

- Radioactive decay of K^{40}, U^{238}, and Th^{232}
  - Gamma rays are the energy emitted as radioactive isotope attempts to achieve its lowest energy state
- Present in variable quantities in all formations
- Average concentrations in Earth's crust
  - Potassium 2%
  - Thorium 9.6 ppm
  - Uranium 2.7 ppm

Potassium-40 decay

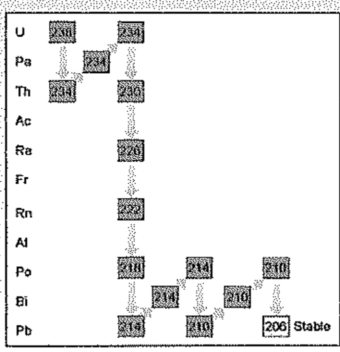
- K^{40} half-life 1.3 billion years
  daughter stable Ar^{40}



- Energy level of emitted gamma ray = 1.46-MeV

Uranium-238 decay

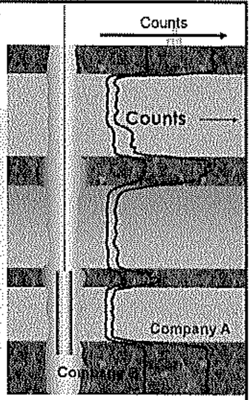
- U^{238} half-life 4.4 billion years
  daughter sable Pb^{206}



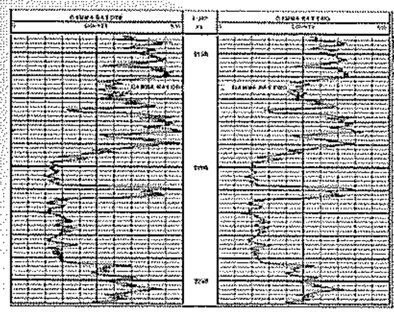
- Complex series of decays
- Resulting gamma rays have a range of energies

Different tools…different count rates…

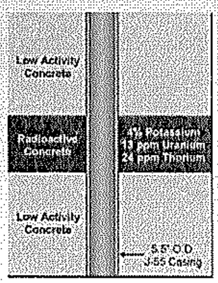
- Company vs. company
- Tool vs. tool



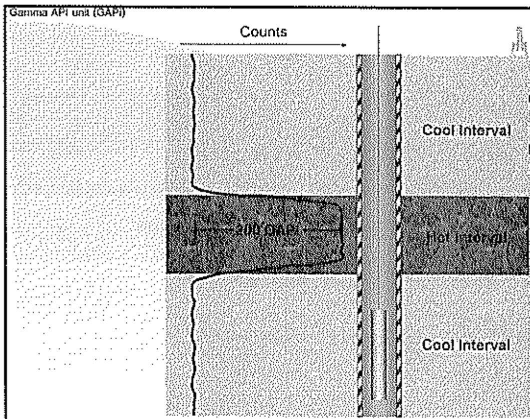
Different tools…different count rates…



API gamma ray test pit



- University of Houston
- The logging company designates a standard tool to measure count rates
- Low-radioactivity concrete and "artificial shale"



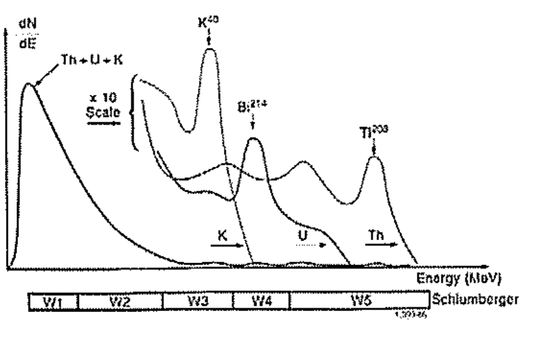
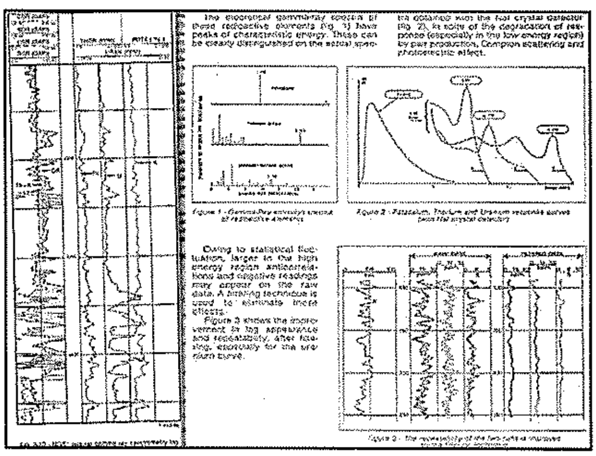


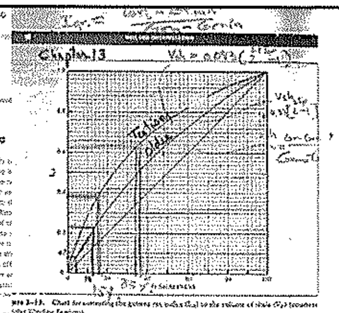
Fig. 3-9—Potassium, thorium, and uranium response curves (NaI crystal detector).

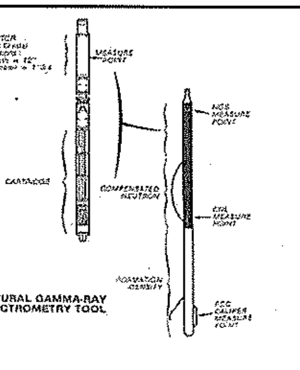


VOLUME OF SHALE FROM SP LOG

$$V_{sh} = 1.0 - \frac{PSP}{SSP}$$

GAMMA RAY AND CALIPER LOG

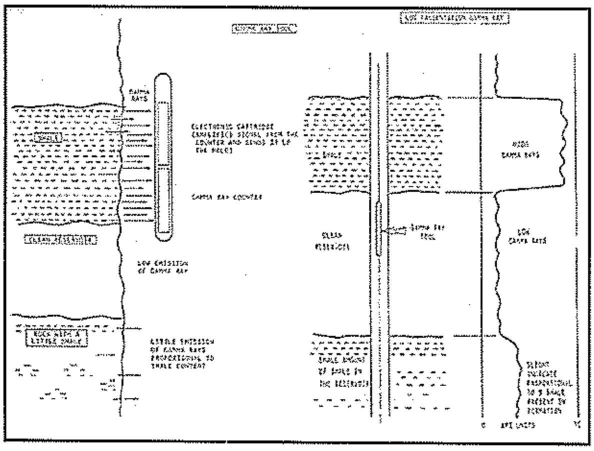




NATURAL GAMMA-RAY SPECTROMETRY TOOL

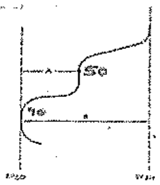
NGS Tool Specifications

Total length	=	10 ft.
Diameter	=	3 5/8 in.
Minimum hole size	=	5 in.
Maximum temperature	=	350°F
Maximum pressure	=	20,000 psi.
Total weight	=	79 kg



SPONTANEOUS POTENTIAL

$$V_{sh} = 1 - \frac{PSP}{SSP}$$



$$V_{sh} = 1 - \frac{50}{90} = \frac{40}{90}$$

GOOD V_{sh} – TIGHT ZONES
– WATER BEARING
– GOOD SP DEFINITION
– LAMINATED SHALE

The Natural Gamma-Ray Spectrometry.. ..... Tool

... is designed to determine the origin of the natural radioactivity of subsurface geological formations penetrated by the well-bore.

This determination is made by computing the formation percentages of the three natural gamma ray emitting elements :

Potassium ^{40}K
Thorium ^{232}Th
Uranium ^{238}U

This is achieved by a spectrometric analysis of the naturally

Advantages of Natural Gamma-Ray Spectrometry

- NGS* gives the origin of the radioactivity and the contribution of each radioactive element to the total gamma radioactivity.
- NGS* improves shale determination.
- NGS* improves lithology determination by addition of two more equations to the standard set :

$$K = \Sigma\ V_i K_{ma_i}$$
$$Th = \Sigma\ V_i Th_{ma_i}$$

Applications

- Well-to-well correlations.
- Improved shale indicators.
- Clay mineral identification and percentage computation.
- Other radioactive mineral recognition resulting in a better lithology determination.
- An approach to cation exchange capacity.
- Definition of facies and depositional environment.
- Estimation of :
  - uranium potential (uranium ores)
  - potassium potential (evaporites)
  - hydrocarbon potential (hydrocarbon source rocks).
- Compaction study.
- Igneous rock recognition.
- Stylolite and fracture identification.

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older + consolidated rocks
$V_{sh} = 0.33(2^{2 I_{GR}} - 1)$

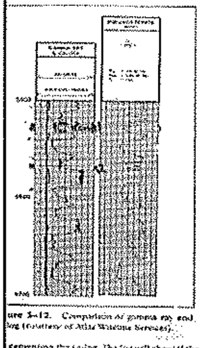


Figure 3-12. Comparison of gamma ray and ... log (courtesy of Atlas Wireline Services).

For tertiary and consolidated rocks:

$V_{sh} = 0.083\ [2^{3.7 I_{GR}} - 1.0]$

Example 3-4. Determine the volume of shale for the zones 5,524–5,530 ft (Zone 1) and 5,566–5,568 ft (Zone 2) in the gamma ray log presented in Figure 3-12. Assume older rocks.

Solution: From the log,

$GR_{max} = 80$ 5,573–5,583 ft
$GR_{min} = 28$ 5,540–5,546 ft
$GR_{zone1} = 33$ $GR_{zone2} = 40$

$(I_{GR})_{zone1} = \frac{33 - 28}{80 - 28} = 0.09$

$(I_{GR})_{zone2} = \frac{40 - 28}{80 - 28} = 0.23$

Using Equation (3.7), the volume of shale would be:

$V_{sh\,zone1} = 0.33\ (2^{2 \times 0.09} - 1.0) \times 100 = 3.87\%$

$V_{sh\,zone2} = 12.39\%$

The caliper log is used to measure the diameter of the wellbore in inches from the top of the hole to the bottom. The size of the hole is required for correcting some of the logs for hole size effects and it also helps in determining hole volume in order to estimate the amount of cement required for cementing the casing. The log will show if there is any swelling or washout, etc., in the hole. ... log is run in conjunction with the SP log or the GR log.

Chapter 7
Gamma Ray Log

7.1 Introduction

7.2 Detection and Measurement of Nuclear Radiation

TABLE 7.1—GAMMA RAY ACTIVITY OF SEDIMENTARY ROCKS (after Ref. 1)

Lithology Type	Average Radioactivity in Radium Equivalent per gram × 10⁻¹²
Black and grayish-black shale	25.1
Shale	20.3
Sandy shale	11.0
Siltstone	10.3
Calcareous shale	6.5
Shaly and silty sand	7.1
Granite wash	6.9
Sand	4.1
Limestone	3.6
Dolomite	3.1

the Geiger-Mueller counter is modified into a proportional counter that produces a signal proportional to the number of ions formed. Thus, it can discriminate between the various types of radiation. Moreover, it operates 100 times faster than the Geiger-Mueller counter.[3]

The scintillation counter (Fig. 7.5) is composed of a fluorescent crystal and a photomultiplier tube. An example of a scintillator is a sodium iodide crystal deliberately contaminated with a small amount of thallium iodide. When the crystal is struck by gamma radiation, it emits ultraviolet or blue-light photons. These photons strike a photosensitive surface (photocathode), which causes the emission of photoelectrons into an electric field. The photoelectrons strike anodes placed at successively higher potentials. At each anode, the electrons multiply as a result of secondary-electron emission. A large number of electrons are collected at the last anode. The electric charge is amplified and recorded.

The scintillation counter is the most suitable instrument for radiation detection. It is characterized by fast reaction and high detection efficiency (50% to 60%). These characteristics allow it to detect thin beds. It also senses gamma energies, making spectrometry possible. The scintillation counter, however, is temperature-sensitive. The crystal scintillating efficiency varies with temperature. The gain

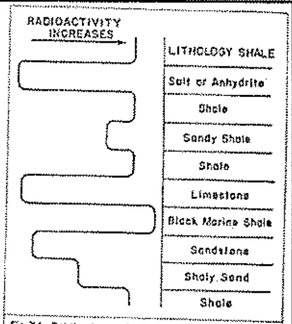


Fig. 7.1—Relative degree of radioactivity of the most common sedimentary rocks.

field calibration. To calibrate a secondary standard, which is usually a jig containing a radioactive pill, a specific tool first is calibrated in the pit. Then, the jig is positioned at a fixed, standardized distance from the tool, and its strength in API units is determined. This calibration is specific to each tool size, source spacing, and detector type.

sion detection. It is characterized by fast reaction and high detection efficiency (50% to 60%). These characteristics allow it to detect thin beds. It also senses gamma energies, making spectrometry possible. The scintillation counter, however, is temperature-sensitive. The crystal scintillating efficiency varies with temperature. The gain of the photomultiplier is also a function of temperature.[5]

7.3 Unit of Measurement

When gamma ray logging was first introduced, comparisons of logs run by different service companies were virtually impossible because they used different units of measurement (e.g., counts per minute, counts per second, radiation units, micrograms of radium-equivalent per ton of formation, and microroentgens per hour).[6]

This lack of standardization prompted the American Petroleum Inst. (API) to appoint a subcommittee to develop a standard practice that would create uniformity to allow direct comparison of radioactivity logs. The subcommittee designed a standard log heading and form and established a standard API unit of measurement for both gamma ray and neutron logs. A calibration facility for nuclear logs was designed and promoted. A standard procedure for presenting calibration data also was developed.[6,7]

The calibration facility, located at the U. of Houston and illustrated in Fig. 7.6, is primarily a pit 4 ft in diameter and 25 ft deep that is filled with three 8-ft-thick zones of radioactive concrete. A 5½-in. casing extends through the concrete sections 15 ft below the bottom of the pit. Radioactivity was obtained by adding radioactive material to a mixture of cement and Ottawa sand. The top and bottom concrete zones are low in activity. The center section, containing about 12 ppm uranium, 24 ppm thorium, and 4% potassium, has approximately twice the radioactivity of an average shale.

The industry adopted the "API gamma ray unit" as the standard for gamma ray log measurements. One API gamma ray unit is defined as 1/200 of the difference in log deflection between the two lower concrete zones of low and high radiation in the calibration pit. All gamma ray tools calibrated to API standards record gamma radiation in the same units of measurements. A tool can be calibrated in the pit. In practice, however, a secondary portable standard is calibrated with the pit. This portable standard, in turn, is used for

a jig containing a radioactive pill, a specific tool first is calibrated in the pit. Then, the jig is positioned at a fixed, standardized distance from the tool, and its strength in API units is determined. This calibration is specific to each tool size, source spacing, and detector type.

7.4 Statistical Variations

Even with the gamma ray sonde stationary in the borehole, the number of gamma rays that reaches the detector varies with time. This is the result of the random nature of radioactive disintegrations. These fluctuations follow mathematical laws of probability and are known as statistical variations. To obtain a representative and reproducible value of radiation intensity for a specific formation, the number of gamma rays should be observed and averaged over a period of time. For good readings, a few seconds are usually required.

Statistical variations have been averaged by using a resistor-condenser (rc) smoothing electric circuit similar to that shown in Fig. 7.7. The electric pulses generated by the detector are passed through a circuit that impresses a charge, Q, on the condenser at each pulse. The current entering the capacitor, I_{in}, is

$$I_{in} = JQ, \qquad (7.1)$$

where J is the pulse rate. The capacitor discharges through the resistor, r. The current leaving the capacitor, I_{out}, is

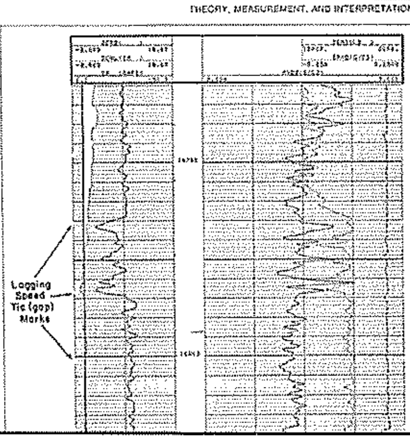
$$I_{out} = V/r, \qquad (7.2)$$

where V is the potential across the condenser. At equilibrium, where $I_{in} = I_{out}$,

$$V = JrQ. \qquad (7.3)$$

Then, the recorded voltage, V, is proportional to the pulse rate—i.e., the radioactivity of the medium generating the pulses.

If the pulse rate varies from J_1 to J_2, the recording device does not react instantaneously to the change. The voltage lags the change. It builds up or draws down vs. time according to[8,9]



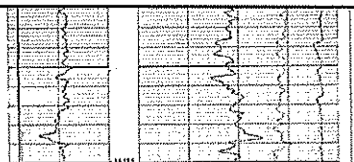


Fig. 7.2—Gamma ray curve recorded with the compensated-neutron/formation-density log.

Eq. 7.4 also can be written as

$$J_a(t) = [1/(r)]Q(t) = J_1 + (J_2 - J_1)(1 - e^{-t/rc}), \qquad (7.5)$$

where $J_a(t)$ is the apparent intensity reflected by the recorder. The meter then provides a running average of the pulse rate. This results in the smoothing out of statistical variations. The product is called the time constant of the electric circuit. When $t = rc$, $(1 - e^{-t/rc}) = 0.63$. One time constant is then the time required for the equipment to record 63% of the change in counts from the previous level. This constant determines the time over which

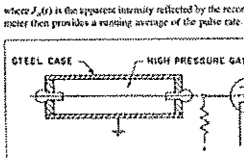


Fig. 7.3—Ionization chamber (after Ref. 2).

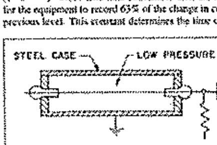


Fig. 7.4—Proportional counter, or Geiger-Mueller Counter (after Ref. 2).

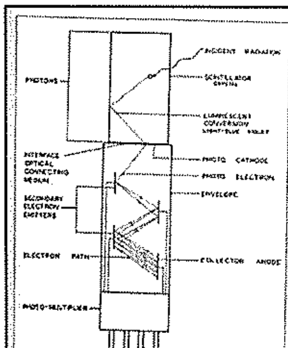


Fig. 7.5—Schematic of scintillator and photomultiplier tube (from Ref. 4).

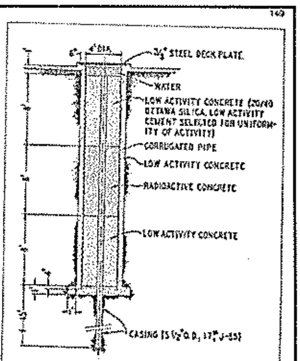


Fig. 7.6—Gamma ray log calibration pit (from Ref. 7).

radioactive counts are averaged. The time constant of a measuring device can be changed by a slight modification of the circuitry. Statistical variations are more pronounced for lower count rates.

The smoothed-out response (Fig. 7.9) indicates that the larger the time constant, the smoother the profile.

radioactive counts are averaged. The time constant of a measuring device can be changed by a slight modification of the circuitry. Statistical variations are more pronounced for lower count rates, so a larger time constant is required for adequate averaging of the variations. In most cases, however, a time constant of 2 seconds is sufficient.[3] To check the appropriateness of the selected time constant, radioactivity of a relatively active formation is recorded for several minutes. This test is called a statistical check. For a log of acceptable quality, the residual fluctuations should not exceed a certain percentage, usually 5% to 15%, of the total change in radioactivity between shales and clean formations.

Example 7.1. Fig. 7.8 shows, hypothetically, the fluctuation of pulse rate vs. time. Show the smoothed-out response generated by the rc circuit having a time constant of 1 second. Repeat for a time constant of 2 seconds. Let the pulse rate immediately before these events be 100 counts/sec.

Solution. Using Eq. 7.5 for the first second gives

$J_a(t)=100+10(1-e^{-t/rc})$.

Values of J_a for $rc=1$ and $rc=2$ calculated from this expression vs. time are listed below.

t (seconds)	J_a, $rc=1$ (counts/sec)	J_a, $rc=2$ (counts/sec)
0	100	100
0.25	102.2	101.2
0.50	103.9	102.2
0.75	105.3	103.1
1.0	106.3	103.9

Calculations for the other time intervals are performed similarly. For example, $J_a(t)$ for $rc=1$ is expressed for the following second as

$J_a(t)=106.3+20[1-e^{-(t-1)/rc}]$.

The smoothed-out response (Fig. 7.9) indicates that the larger the time constant, the smoother the profile.

7.5 Logging Speed

The number of pulses averaged by the detector depends on the radiation intensity, the counter's efficiency, the time constant, and the logging speed. An increase in logging speed is equivalent to an apparent delay of equipment reactions to a change in radiation intensity: the higher the speed, the smoother the tool response and vice versa. Fig. 7.10 shows the effect of speed on log quality. The same section of a well is logged at speeds of 720 and 2,700 ft/hr. The quality of these logs is different. Beds are not defined as well on the 2,700-ft/hr log. But bed resolution also depends on the time constant; a better resolution calls for a smaller time constant. A good-quality log should be run with an optimum combination of logging speed and time constant.

Example 7.2.

a. A 10-ft-thick hypothetical bed with an average radioactive intensity of 100 counts/sec lies between two infinite beds of zero radioactivity. Show the response of a point detector having a time constant of 4 seconds run at a speed of 3,600 ft/hr.

b. Repeat for a speed of 900 ft/hr.

c. If a logging speed of 1,800 ft/hr is used, what time constant, if any, reproduces the response calculated in Part b?

Solution.

a. From Eq. 7.5,

$J_a(t)=100(1-e^{-0.25t})$,

where t is the time elapsed since the tool left the lower bed boundary.

If z is the tool location above the same boundary, then for a speed of 3,600 ft/hr, the following data are obtained.

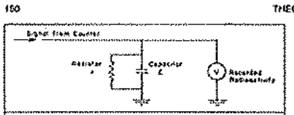


Fig. 7.7—Circuit for averaging statistical variations (from Ref. 8).

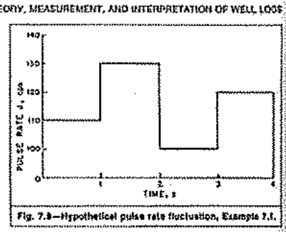


Fig. 7.8—Hypothetical pulse rate fluctuation, Example 7.1.

t (seconds)	z (ft)	$J_a(t)$ (counts/sec)
0	0	0
1	1	22
2	2	39
3	3	53
4	4	63
5	5	71
6	6	78
7	7	82
8	8	87
9	9	90
10	10	92

b. For a speed of 900 ft/hr, the values given below result.

t (seconds)	z (ft)	$J_a(t)$ (counts/sec)
0	0	0
2	0.5	39
4	1	63
6	1.5	78
8	2	87
10	2.5	92
20	5	99
40	10	100

The logging-speed/time-constant combination results in two effects.

1. The log response is not representative of a bed whose thickness is less than the critical thickness—i.e., the distance traveled by the sonde in one time constant.

2. An anomaly is shifted in the direction in which the tool is moving. This lag, as well as the critical thickness, is expressed by[8]

$$h_t = vt_c \quad (7.7)$$

where h_t = lag or critical thickness, ft; v = logging speed, ft/sec; and t_c = time constant, seconds. To avoid excessive distortion of the gamma ray curve, v and t_c are chosen so that the lag h_t is about 1 ft. Most common logging speeds and corresponding optimum time constants are as shown below.

Fig. 7.11 graphically presents these two cases. The intensity above the top bed boundary for the 3,600- and 900-ft/hr cases is calculated from the following two equations, respectively:

$J_a(t)=92e^{-0.25(t-10)}$

and $J_a(t)=100e^{-0.25(t-40)}$.

c. J_a given by Eq. 7.5 can be expressed as a function of z:

$$J_a(z)=J(0)\{1-e^{-[z/v(rc)]}\}, \quad (7.6)$$

where v is the logging speed in feet per second. Eq. 7.6 indicates that identical responses are obtained vs. depth for different speeds, provided that the product $v(rc)$ remains the same. The profile of Part b, obtained with a speed of 900 ft/hr and a time constant of 4 seconds, can be reproduced at a logging speed of 1,800 ft/hr but at a time constant of 2 seconds.

v (ft/hr)	t_c (seconds)
3,600	1
1,800	2
1,200	3
900	4

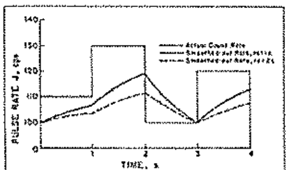


Fig. 7.9—Smoothed-out fluctuation using rc circuit, Example 7.1.

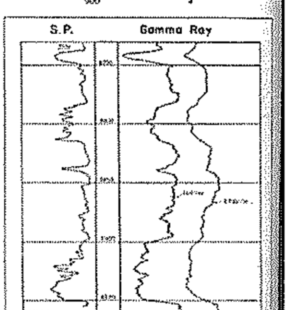


Fig. 7.10—Effect of speed. Log of the same section recorded at a speed of 720 and 2,700 ft/hr (from Ref. 5).

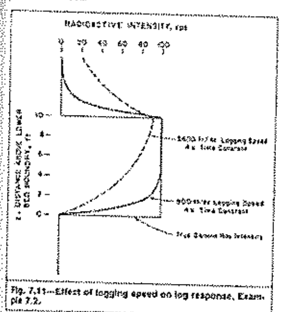


Fig. 7.11—Effect of logging speed on log response, Example 7.2.

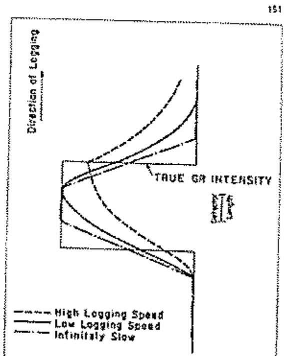


Fig. 7.12—Effect of detector length on gamma ray curve shape (after Ref. 9).

The logging speed is usually indicated by the marks or gaps in the far left vertical line of the first track. These ticks are spaced 1 minute apart. For example, the log of Fig. 7.2 shows gaps spaced 35 ft apart; this indicates that the logging speed was 35 ft/min or 2,100 ft/hr.

The theoretical tool responses shown so far assume a point detector. A detector of appreciable length is used in actual logging. This results in additional smoothing of the curve, as illustrated by Fig. 7.12.

New equipment uses an averaging technique other than the rc circuit. One method consists of averaging the reading obtained at one depth with the readings that immediately precede and follow.

7.6 Tool Response

The gamma ray tool response, recorded with an optimum speed and time constant with the tool situated opposite a given formation, depends on several factors: specific formation radioactivity, A—i.e., gamma rays/sec·g; formation bulk density, ρ_b; specific activities of the borehole fluid; density of the borehole fluid; hole diameter; characteristics of the detector and the counting system; and position of the detector in the borehole—i.e., eccentricity. In a cased hole, the tool response also depends on the specific activities of the casing and cement and on the thicknesses and densities of the casing and cement.

For qualitative interpretation, the borehole-environment effect (i.e., borehole fluid, cement, and casing) can be neglected because the interpretation relies on relative variation from one zone to another and because the borehole conditions affecting the gamma ray remain practically unchanged over long borehole sections. For quantitative interpretation, the effect should be taken into consideration, especially in large and cased holes.

Service company chart books contain charts to correct for borehole effect. Fig. 7.13 is an example. This chart, which is based largely on laboratory experiments, gives the ratio of corrected gamma ray, γ_{cor}, to the gamma ray log response, γ_{log}, as a function of hole size and mud weight for centered and eccentered tools. γ_{cor} is defined as the response of a 3⅝-in. tool eccentric in an 8-in. hole filled with 10-lbm/gal mud. There are considerable normal measurement conditions. In most cases, boreholes deviate from the vertical and the sonde can be assumed eccentric.

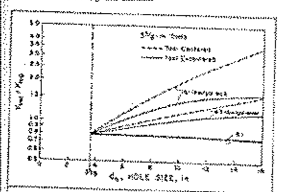


Fig. 7.13—Gamma Ray Correction for hole size and mud weight, after Ref. 12.

Example 7.3. A gamma ray log was recorded in an empty, open hole drilled with a 7⅞-in. bit. The gamma ray device is 3⅝ in.

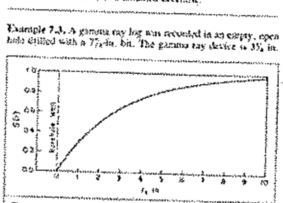


Fig. 7.14—Integrated radial geometric factor of the gamma ray log under the conditions stated in Example 7.4.

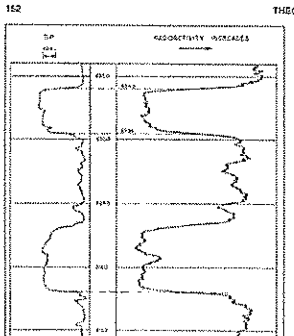


Fig. 7.15—SP and gamma ray logs recorded simultaneously in an open hole (from Ref. 9).

in diameter and runs simultaneously with a Formation Density Compensated (FDC™) tool.

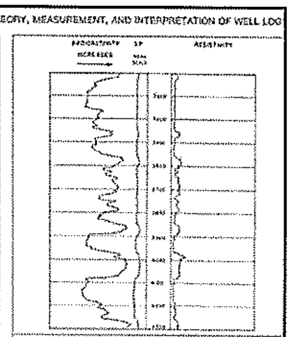


Fig. 7.16—Gamma ray and SP log recorded in high-salinity mud, $R_{mf} \approx R_w$ (from Ref. 9).

After the borehole-environment effect is normalized, the corrected response is proportional to the weight concentration of radioactive materials in the formation. It can be expressed for a formation containing n specific radioactive minerals as[11] pensated (FDC[SM]) tool.

a. Determine the corrected radioactivity, γ_{corr}, of a zone that registered 30 API units on the log.

b. On a subsequent run, with the same equipment, the hole has been filled with 10-lbm/gal mud. What level of radioactivity would now be displayed by the log for the same zone?

c. Repeat Part b for a 16-lbm/gal mud.

d. Repeat Parts b and c for the case where the gamma ray device is run simultaneously with a Borehole Compensated Sonic (BHC[SM]) tool.

Solution.

a. From Fig. 7.13,

$\gamma_{cor}/\gamma_{log} = 0.79$

and $\gamma_{cor} = 0.79(30) = 23.7 \approx 24$ API units.

b. Because the FDC is run in an eccentric fashion, the borehole environment closely matches that used to define γ_{cor} (8-in. borehole, 10-lbm/gal mud, and tool eccentricity). Therefore, $\gamma_{log} = \gamma_{cor} = 24$ API units.

c. For prevailing conditions and 16-lbm/gal mud, the chart in Fig. 7.11 gives

$\gamma_{cor}/\gamma_{log} = 1.2$

and $\gamma_{log} = 24/1.2 = 20$ API units.

d. Gamma ray devices are run simultaneously with the BHC centered. This affects the log reading. For a 10-lbm/gal mud,

$\gamma_{cor}/\gamma_{log} \approx 1.1$

(by interpolation) and

$\gamma_{log} = 24/1.1 \approx 22$ API units.

For the 16-lbm/gal mud,

$\gamma_{cor}/\gamma_{log} = 1.46$

and $\gamma_{log} = 24/1.46 \approx 16$ API units.

$$\gamma = \frac{1}{\rho_b} \sum_{i=1}^{n} \rho_i V_i a_i \quad (7.8)$$

$$= \frac{1}{\rho_b} \sum_{i=1}^{n} B_i V_i, \quad (7.9)$$

where ρ_i = density of the radioactive mineral, V_i = bulk volume fraction of the mineral, a_i = proportionality factor that corresponds to the radioactivity of the mineral and depends on the detector used and the sonde design, and $B_i = \rho_i a_i$ = a constant for each specific radioactive mineral.

For Schlumberger devices, the relation between the concentration of K, Th, or U and the total gamma ray signal recorded in common sedimentary rocks can be approximated by[13]

$$\gamma = 4C_{Th} + 8C_U + C_K, \quad (7.10)$$

where γ = total gamma ray, API units; C_K = potassium concentration, wt%, and C_{Th} and C_U = thorium and uranium concentrations, respectively, in ppm. If the effect of formation density needs to be taken into account, the gamma ray log may be normalized by multiplying it by the bulk density value obtained from the density log.

The depth of investigation of the gamma ray tool (i.e., the volume of the formation contributing the major portion of the tool response) is difficult to determine by experimentation. An analytical treatment using Monte Carlo simulation shows that, in general, 90% of the signal comes from a shell 6 in. thick.[14] A less sophisticated calculation shows that the integrated radial geometric factor, $G(r)$, can be expressed as[15]

$$G(r) = 1 - e^{-r/\bar{\lambda}}, \quad (7.11)$$

where r is the radial distance measured from the borehole wall and $\bar{\lambda}$ is the mean free path. The mean free path, discussed in Sec. 2.7.3, is the average distance traveled by a photon in a medium between

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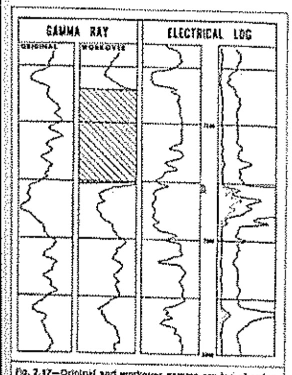

Fig. 7.17—Original and workover gamma ray log showing water channeling behind the casing (from Ref. 15).

where γ_{log} is the log response in the zone analyzed, and γ_{sh} and γ_{min} are the log responses in shales and in zones of minimum radioactivity, respectively. I_{sh} is converted to shale content, V_{sh}, with the method detailed in Sec. 15.3.

In mineral exploration, gamma ray logging is used to detect radioactive minerals, such as potash or uranium, and nonradioactive minerals, such as coal.

The gamma ray log is particularly useful in cased-hole applications in both completion and production operations. The simultaneous recording of a casing-collar locator and the gamma ray is indispensible for accurate positioning of perforating guns and other downhole devices. Openhole information is tied to cased-hole conditions by correlation of an openhole SP or gamma ray log to the cased-hole gamma ray log, which, in turn, is tied to the casing-collar locations. Instead of measured depth, which usually differs from true depth by a few feet, the gun or any other tool is positioned with respect to the collars.

Application of gamma ray logging in production operations abounds. For example, prolonged fluid migration behind casing or through perforations causes radioactive anomalies that are easily recognizable on gamma ray logs.[15] Fig. 7.17 shows openhole electrical and gamma ray logs recorded in a well completed in the 7,652 to 7,658-ft interval. It also shows a workover gamma ray run 2 years later to identify the source of a sudden increase in water production. Because the workover log showed an abnormally high radioactivity throughout the interval between the top of the perforation and the base of the next-higher saltwater sand, it was concluded that water production was caused by water channeling from this sand through the cement sheath. With this information, appropriate measures were taken, and the well was restored to water-free production.

The gamma ray log is also at the heart of radioactive-tracer logging. In this process, the fluid pumped into a borehole or a formation carries gamma-ray-emitting isotopes, either in solution or in

successive interactions. $\bar{\lambda}$ depends on photon energy and the medium density.

Example 7.4. Plot the integrated geometric factor vs. radius for an 8-in. borehole with a formation density of 2.65 g/cm³, where the K^{40} radiation is detected by the tool.

Solution. From Eqs. 2.38 and 2.32,

$\bar{\lambda} = 1/\sigma_l = 1/\rho\sigma_m$,

where ρ is the medium bulk density and σ_l and σ_m are the linear and mass absorption coefficients, respectively. K^{40} emits gamma rays of 1.46-MeV energy. From Table 2.5, $\sigma_m = 0.05127$ cm²/g. Then,

$\bar{\lambda} = 1/(2.65 \times 0.05127) = 7.36$ cm $= 2.9$ in.

Eq. 7.11 reduces to

$G(r) = 1 - e^{-0.345r}$,

where r is in inches. Fig. 7.14 is a plot of this function. Fig. 7.14 indicates that the first 7 in. of the formation generates 90% of the signal under the stated conditions.

7.7 Applications of the Gamma Ray Log

With few exceptions, the gamma ray log correlates very well with the SP log, as illustrated in Fig. 7.15. Like the SP log, the gamma ray log can be used to delineate shale beds and to correlate between wells. The gamma ray log substitutes for the SP log when the SP is flat as a result of low contrast between R_{mf} and R_w (Fig. 7.16) and when the SP log cannot be recorded, as in the case of oil-based mud, empty holes, and cased holes.

When potassium is the only or the major contributor to shale radioactivity, the gamma ray log response is used to estimate the shale content. A shale index, I_{sh}, is calculated from

$$I_{sh} = (\gamma_{log} - \gamma_{min})/(\gamma_{sh} - \gamma_{min}). \quad (7.12)$$

suspension. A gamma-ray log run later will display an increase in radioactivity opposite zones that experienced fluid intake. Radioactive-tracer logging is used to determine waterflood injection profiles, zone response to fracture treatment, loss of circulation, casing leaks, perforated zones, and cement location.[16] Fig. 7.18 shows an example of a gamma ray used to locate cement carrying a radioactive tracer. Gamma ray Run 1 is a base log obtained before cementing. Gamma ray Run 2 was made after 125 sacks of radioactive cement was pumped through perforations located at 3,678 to 3,692 ft.

7.8 Gamma Ray Spectrometry Log

The gamma ray log provides a measure of the total natural radioactivity of a formation, regardless of its energy level or energy spectrum. The spectral gamma ray log, or gamma ray spectrometry tool, also detects the naturally occurring gamma rays and defines the energy spectrum of the radiation. Because potassium, thorium, and uranium are responsible for the energy spectrum observed by the tool, their respective elemental concentrations can be calculated.[17]

Fig. 2.6 shows the gamma-ray-emission spectrum of the potassium, uranium, and thorium series. The observed spectrum is of a continuous rather than a discrete form. This results mainly from a detector-type depth of investigation and logging speed. Fig. 7.19 illustrates the continuous spectrum obtained with a sodium iodide crystal scintillation detector. The spectrum shows three distinctive peaks characteristic of the three sources of natural radioactivity. These peaks are at energy levels of 2.62, 1.76, and 1.46 MeV. They correspond to gamma ray emissions associated with the decay of thallium (Tl^{208}) bismuth (Bi^{214}) and potassium (K^{40}), respectively. The three peaks are used to distinguish the thorium, uranium, and potassium because they are sharp and of relatively high magnitude.

One method for analyzing the pulse height is to divide the energy spectrum into several energy ranges known as windows. Fig. 7.19 shows the five window system Schlumberger uses. The pulses that correspond to each window are recorded with a specific de-

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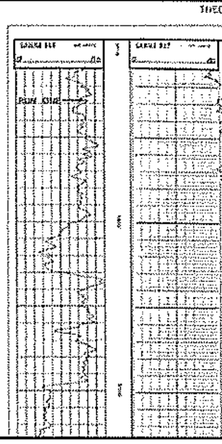

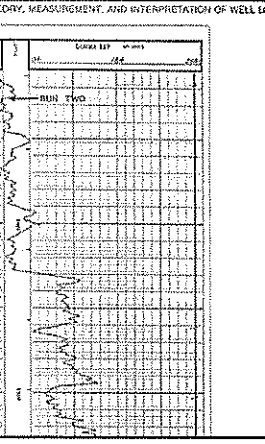

Fig. 7.18—Example of gamma ray logs used to locate radioactive cement (courtesy Schlumberger).

tector. The elemental concentrations are estimated by the matrix relationship[17]

$$[0] = [M][W], \quad (7.13)$$

where [0] is the vector of Th, U, and K concentrations,

$$[0] = \begin{bmatrix} C_{Th} \\ C_U \\ C_K \end{bmatrix}, \quad (7.14)$$

[W] is the vector of five window count rates, R_i,

$$[W] = \begin{bmatrix} R_1 \\ R_2 \\ R_3 \\ R_4 \\ R_5 \end{bmatrix}, \quad (7.15)$$

and [M] is the 3×5 matrix of estimation coefficients, B_{ij}, for Window i and Element j.

$$[M] = \begin{bmatrix} B_{1,Th} & B_{1,U} & B_{1,K} \\ B_{2,Th} & B_{2,U} & B_{2,K} \\ \vdots & \vdots & \vdots \\ B_{5,Th} & B_{5,U} & B_{5,K} \end{bmatrix} \quad (7.16)$$

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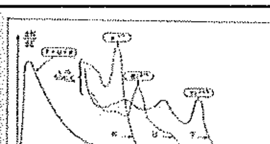


Fig. 7.19—Natural gamma ray energy spectrum determined with sodium iodide crystal detector (from Ref. 17).

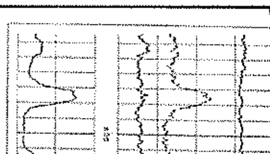
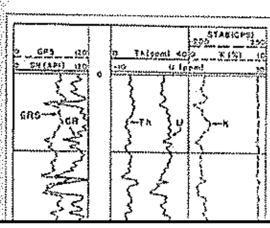
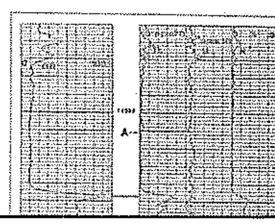


Fig. 7.21—Apparent shale response caused by high-uranium streak in a northern California well (from Ref. 18).





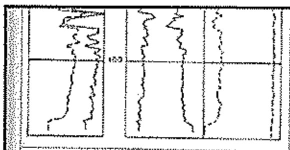


Fig. 7.20—Typical presentation of the gamma ray spectrometry tool (from Ref. 17).

The matrix coefficients B_{ij} are determined for each tool in calibration pits built of formations that contain known quantities of the three elements.

Eq. 7.13 is solved for each level of the borehole, and the results are represented in a form similar to that shown in Fig. 7.20. The log shows thorium and uranium curves scaled in parts per million and a potassium curve scaled in percent. The conventional total gamma ray log is also presented. It is obtained by linear combination of the three elements' individual responses and by use of a relationship similar to that expressed in Eq. 7.10. A "uranium free" gamma ray curve (GRS in Fig. 7.20) obtained by combining only the potassium and thorium can also be presented. The log quality is indicated by a stabilization curve recorded in some cases.

The gamma ray spectrometry log has several potential applications in geological and engineering studies. The amounts and types of elements present in a formation are determined by the way the formation is deposited and what has happened to it since deposition. The concentration curves calculated show a correlation to depositional environment, diagenetic processes, clay type, and clay volume.[17]

One major application is the estimation of shale content. On the conventional gamma ray log, high-radioactivity zones were con-

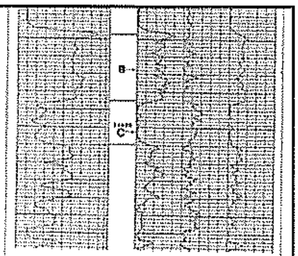


Fig. 7.22—Clean Zone C appears as shaly on the gamma ray log because of the presence of uranium (courtesy Atlas Wireline Services).

sidered to be shale and were not analyzed; or if they were analyzed, a shale correction was applied that could have resulted in a misleading interpretation. An example (Fig. 7.21) was obtained through a sandstone encountered in a southern Oklahoma well. The high-API value appearing on the gamma ray log at 570 to 580 ft could be interpreted as a shale streak. With the benefit of the spectrometry log, it was determined that the high radioactivity was actually caused by high uranium concentration in a sandstone streak. This uranium was deposited from solutions migrating through the permeable streaks of the formation. This zone, in fact, was found to be a productive hydrocarbon zone.[17]

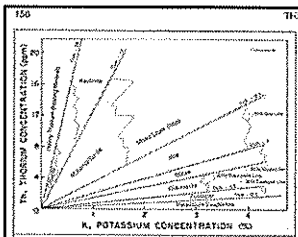


Fig. 7.23—Mineral identification from natural gamma ray spectrometry log (from Ref. 12).

A shale index, I_{sh}, can be calculated from the gamma spectrometry log information:

$$(I_{sh})_{Th}=[(C_{Th})_{log}-(C_{Th})_{min}]/[(C_{Th})_{sh}-(C_{Th})_{min}], \quad \ldots (7.17)$$

$$(I_{sh})_{K}=[(C_{K})_{log}-(C_{K})_{min}]/[(C_{K})_{sh}-(C_{K})_{min}], \quad \ldots (7.18)$$

and/or $(I_{sh})_{\gamma_{uf}}=[(\gamma_{uf})_{log}-(\gamma_{uf})_{min}]/[(\gamma_{uf})_{sh}-(\gamma_{uf})_{min}]. \quad \ldots (7.19)$

C_{Th}, C_K, and γ_{uf} are the log responses indicated by the thorium, potassium, and uranium-free curves, respectively. The subscripts sh and min refer to the logs' responses in shales and in zones that indicate a minimum level of radioactivity. The I_{sh} values calculated from Eqs. 7.17 through 7.19 are more representative than

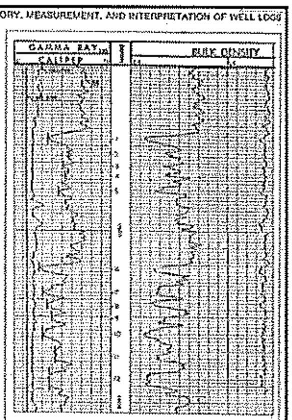


Fig. 7.24—GR log of Problem 7.3 (courtesy Amoco Production Co.).

those obtained from the gamma ray. This results from the exclusion of uranium, which is associated with radioactive minerals other than those found in shale—i.e., organic materials. For example, Zone C in Fig. 7.22 appears shaly on the gamma ray log. However, it contains almost no thorium or potassium, which indicates that it is clean.

Clay minerals can be identified from the crossplot in Fig. 7.23 from potassium and thorium concentrations. Because the compositions of many clay minerals vary somewhat, a mineral location on the plot is not a unique point but a general area. Zone B in Fig. 7.22 plots as mixed-layer clays.

Example 7.5. Calculate the uranium-free gamma ray (γ_{uf}) for Levels A through C of Fig. 7.22. Estimate the I_{sh} of each zone using the total and uranium-free gamma ray levels. Which of the two is the better estimate?

Solution. Log readings at the three levels are as given below.

Level	γ (API units)	C_{Th} (ppm)	C_U (ppm)	C_K (%)
A	10	0	1.25	0
B	60	3.5	0	1.7
C	24	0	3	0

γ_{uf} is estimated with Eq. 7.10:

$\gamma_{uf}=\gamma-8C_U$,

where γ_{uf} and γ are in API units and C_U is in ppm.

The shale indices $(I_{sh})_1$ and $(I_{sh})_2$ are derived from total gamma ray, γ, and uranium-free, γ_{uf}, responses with Eqs. 7.12 and 7.19:

$(I_{sh})_1=(\gamma-10)/(20-10)$

and $(I_{sh})_2=(\gamma_{uf}-0)/(60-0)$.

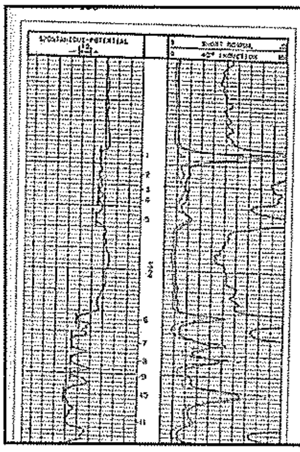
The values of γ_{uf}, $(I_{sh})_1$, and $(I_{sh})_2$ are listed below.

Level	γ_{uf} (API units)	$(I_{sh})_1$ (%)	$(I_{sh})_2$ (%)
A	0	0	0
B	60	100	100
C	0	28	0

The value of $(I_{sh})_2$ derived from the uranium-free value is more representative.

Review Questions

1. What formation property does the gamma ray log reflect?
2. Is the gamma ray response a rigorous lithology indicator? Explain.
3. Why do the SP and gamma ray curves correlate in shale and sand sequences of sediments?
4. Discuss the concepts, advantages, and disadvantages of the different detectors used in radiation logging.
5. What is meant by the efficiency of a radiation detector? What determines such efficiency?
6. What is the standard unit of gamma ray measurement? What prompts the use of this unit? How is it defined?
7. How are gamma ray logging devices calibrated to this standard unit?
8. Even with the tool stationary in the borehole, the amount of radiation passing through the detector fluctuates with time. What is this phenomenon called? Describe two methods used to smooth out these fluctuations.
9. What is meant by the "time constant" of a gamma ray logging tool? How does it control measurement quality?
10. How does logging speed affect log quality? How is the optimum speed selected?



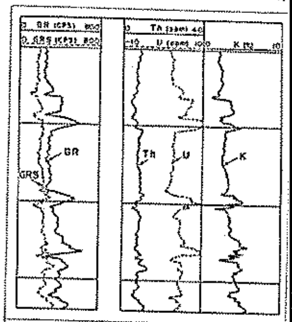


Fig. 7.25—Gamma ray spectrometry log of Problem 7.5 (from Ref. 17).

c. One of the twelve zones considered is abnormal—i.e., it does not fall into either of the two previous patterns. Which zone is it? How does it differ from the other zones? What is the nature of its abnormality?

7.4 A typical average shale contains 12 ppm ...

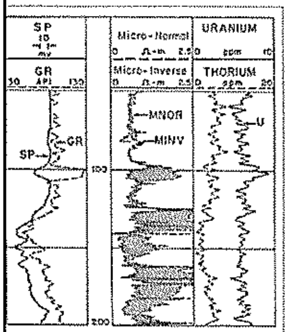


Fig. 7.27—Gamma ray spectrometry log of Problem 7.6 (from Ref. 17).

R_w = formation-water resistivity, Ω·m

t = time, seconds

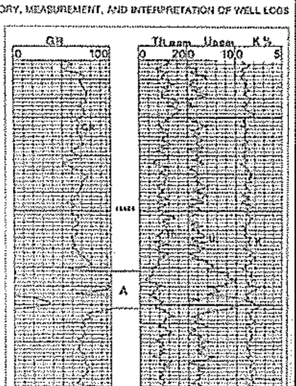


Fig. 7.26—Gamma spectrometry log of Problem 7.7 (courtesy Atlas Wireline Services).

CHAPTER 3 PROBLEMS (Optional)

HW NO 3; DO THE PROBLEM CHAPTER 3; 3 and 5 and Chapter 5; 5.2 In TEXT by Hilchie Chapter 5 In SPE TEXT; 5.15 and 5.17

DOUGLA W. HILCHIE

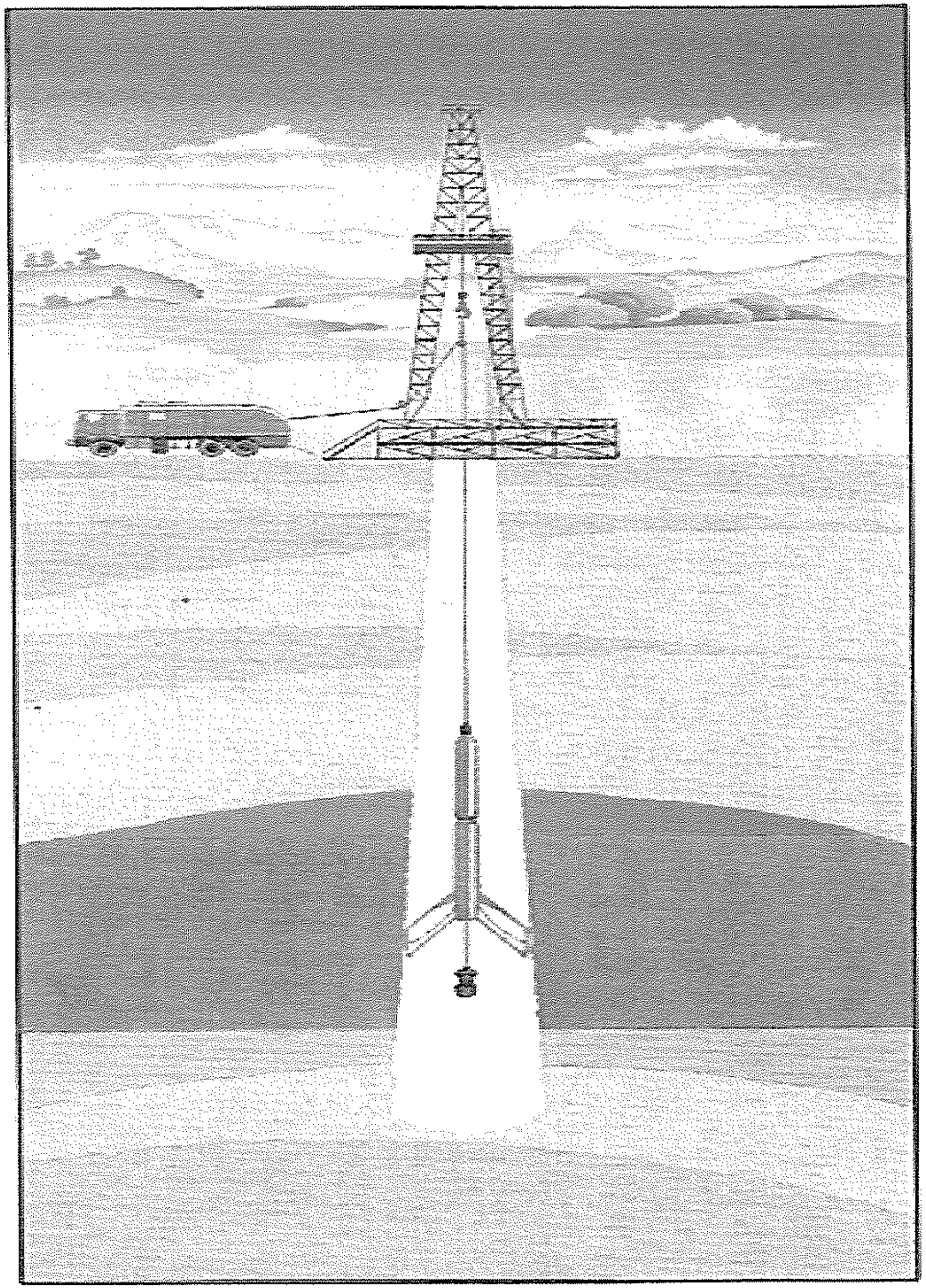


Fig. 1-2—Wireline logging operation.

WELLLOGGING

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CHAPTER6

CHAPTER7

434359,505359 WELL LOGGING 2013(3/2555)

COURSE OUTLINES

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)
Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)
Resistivity Device(2 hrs.)
Spontaneous Potential (SP) Log(2 hrs.)
Induction Electric and Dual Induction Logs(2 hrs.)
Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
Openhole Log and QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Fracture Detection with Well Logs(1 hr.)
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)
Special Logs(1 hrs.)

TEXT BOOKS

DOUGLA W. HILCHIE , ***APPLIED OPENHOLE LOG INTERPRETATION,*** (for Geologists and Engineers) Revised 1982.

REFERENCES

Schlumberger , ' LOG INTERPRETATION PRINCIPLES/APPLICATIONS " 1989
M. A. MIAN, " PETROLEUM ENGINEERING Handbook for the Practicing Engineer ', Volume I, PennWell Books , 1992
Petro Canada " Fundamentals of Core Analysis and Special Core Analysis', PTT.EP. Training, 1988.

GRADING

Homework	25 %
Quiz I, II	20 %
Mid Term	25 %
Final Exam	30 %

ACOUSTIC AND CALIPER LOGS
CHAPTER 6

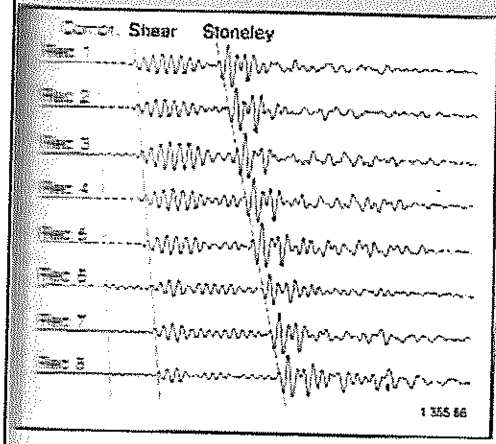


Fig. 5-1—Example waveforms from the eight-receiver Array-Sonic tool.

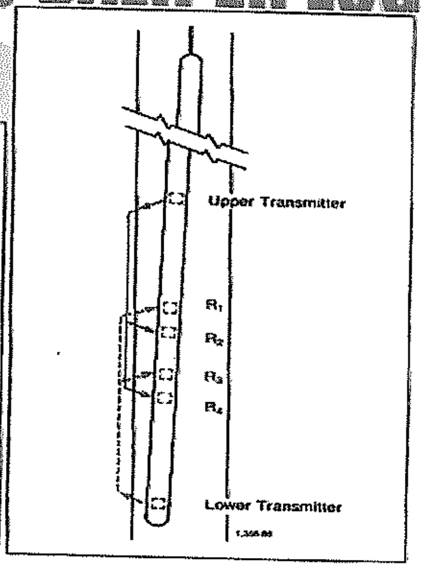
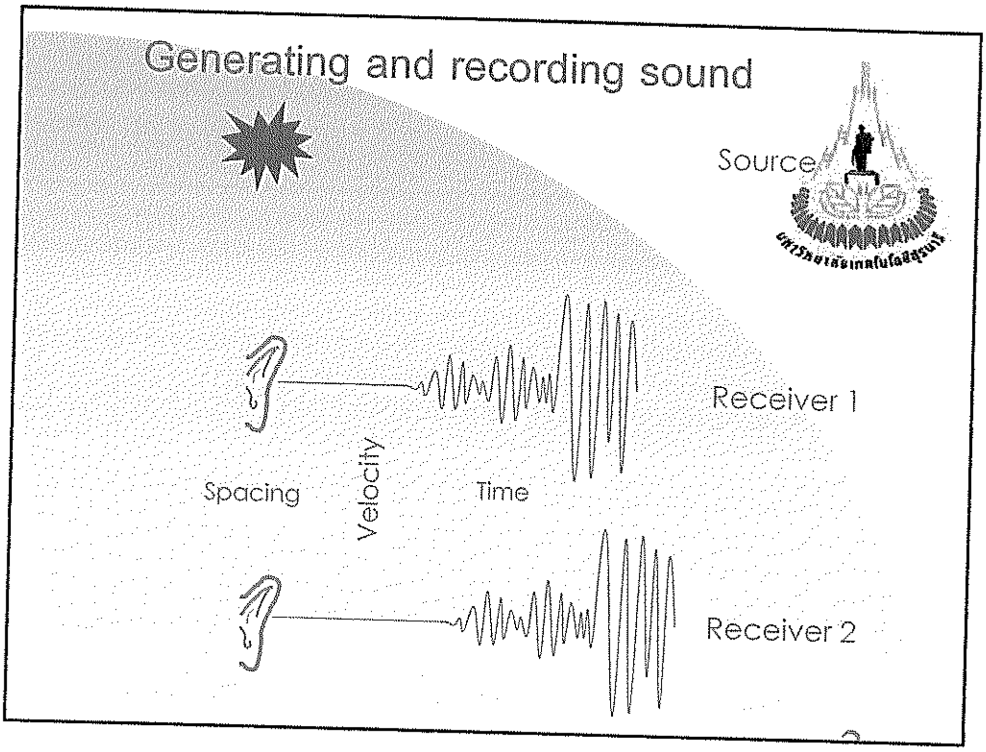


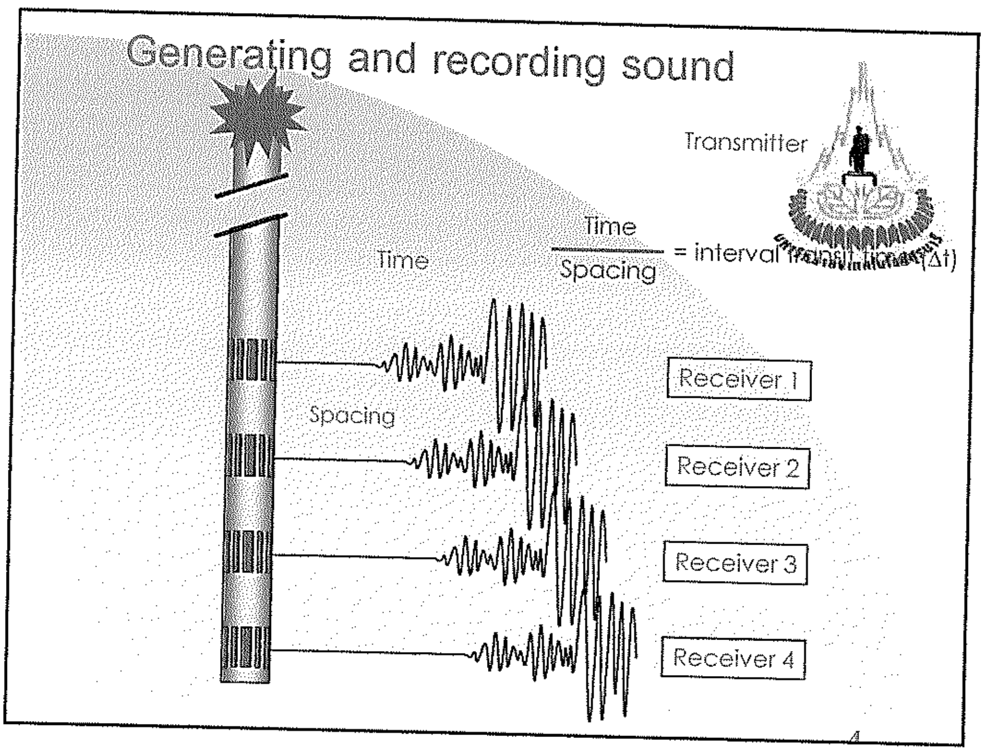
Fig. 5-2—Schematic of BHC sonde, showing ray paths for the two transmitter-receiver sets. Averaging the two Δt measurements cancels errors from sonde tilt and hole-size changes. (Ref. 2)

Acoustic applications

- Full Wave Sonic - compressional <u>and</u> shear velocities…
- Determine porosity
  - Identify lithology
  - Locate gas-bearing zones
  - Indicate permeability variations with depth
  - Detect natural fractures in the formation
  - Determine rock elastic constants
  - Estimate formation strength and least horizontal stress
  - Predict vertical extent of hydraulic fractures

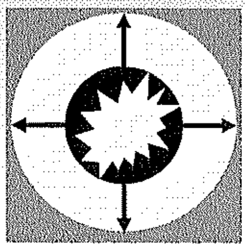
Some applications require data from other tools


Generating and recording sound
Source
Receiver 1
Spacing
Velocity
Time
Receiver 2


Generating and recording sound
Transmitter
Time
Time / Spacing = interval transit time (Δt)
Receiver 1
Spacing
Receiver 2
Receiver 3
Receiver 4

Piezo-electric transmitters

- Intermittent firing (2.5 firings per second for FWS/LSS)
- Electrical impulse converted to mechanical energy
- Omni-directional ("monopole")
- Energy travels as a fluid pressure wave through borehole fluid

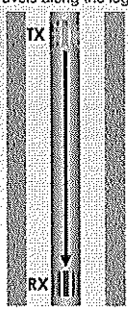


Types of acoustic waves generated

- Several types of acoustic energy are propagated up and down the borehole and through the formation
  - Direct waves (travel along tool or through mud)
    - Tool mode
    - Mud wave
  - Surface waves (travel along borehole wall)
    - Pseudo-Rayleigh waves (normal mode)
    - Stoneley waves
  - Body waves (travel through "body" of formation)
    - Compressional waves (P-waves)
    - Shear waves (S-waves)

Direct waves: tool mode

- Travels along the logging tool



- Travels along the logging tool
- Would be the first waveform to arrive at a receiver (acoustic "short circuit")
- Would not be characteristic of formation properties

How do we minimize tool mode?

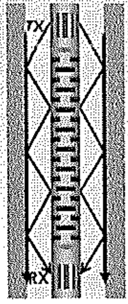
Direct waves: tool mode

- Travel time increased dramatically by slotted isolator

- Slots increase the length of the
- Result is that tool mode arrives at a receiver much later in time, and does not interfere with more important arrivals

Surface waves: pseudo-Rayleigh waves

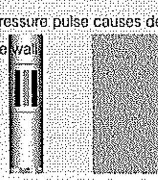
- Also called "normal mode"



- Created by constructive interference of reflected waves and shear waves propagating along formation
- Pseudo-Rayleigh waves propagate along the interface between the borehole and formation ("surface")
- Not characteristic of formation properties (involve reflection in mud)

Generating body waves

- Fluid pressure pulse causes deformation of rock as it impinges borehole wall



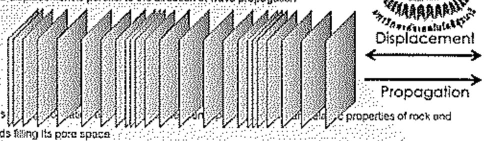
- Deformation occurs at the molecular level as mechanical energy causes the displacement of particles
- Acoustic energy travels through the formation
- This energy may ultimately be detected at a receiver

Body waves—travel through the body of the formation

compressional waves and shear waves

Body waves: compressional waves

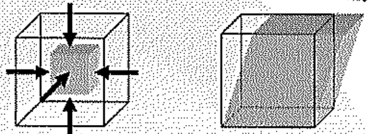
- Particle displacement is parallel to the direction of wave propagation



- Travels … properties of rock and the fluids filling its pore space
- Also called a P-wave ("primary")

What is a "modulus"?

$$\text{modulus} = \frac{\text{stress}}{\text{strain}} \qquad \text{stress} = \frac{\text{force}}{\text{area}} \qquad \text{strain} = \text{defor…}$$



$$K = \frac{F \times V}{A \times \Delta V} \qquad \mu = \frac{F \times L}{A \times \Delta L}$$

Body waves: compressional waves

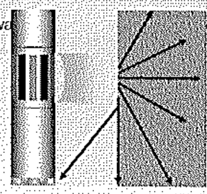
- The fastest body wave (thus, P-wave!)
- 1.4 – 1.9 times faster than a shear wave

$$V_P = \left(\frac{K + \frac{4}{3}\mu}{\rho}\right)^{1/2}$$

- V_P = velocity of compressional wave
- K = bulk modulus of medium
- μ = shear modulus of medium
- ρ = density of medium
- Will a P-wave travel through liquid?

Body waves: compressional waves

- P-wa… …cted

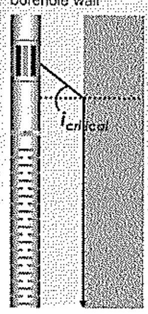


- Reflected into the borehole
- "Critically refracted" along the borehole wall
- Totally refracted into formation

- Think about the first arrival of a compressional wave
  - Which of these paths will it have traveled?

Body waves: compressional waves

- At some angle ($i_{critical}$), a P-wave will be critically refracted along the borehole wall

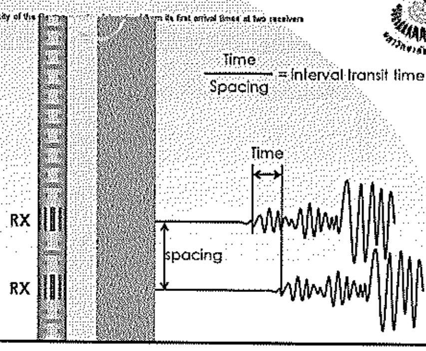


- Critical refraction represents the path of minimum time (results in the first arrival)
- P-wave is critically refracted through the formation
- Compressional energy is re-radiated into the borehole, and can then be detected by a receiver

Body waves: compressional waves

- Velocity of the … from its first arrival times at two receivers

$$\frac{\text{Time}}{\text{Spacing}} = \text{Interval transit time } (\Delta t)$$



Body waves: compressional waves

- How fast is "fast"?

Lithology	Comp. Velocity (feet/second)	(µsec/foot)
Dolomite (Φ = 0%)	22,988	43.5
Limestone (Φ = 0%)	21,000	47.6
Sandstone (Φ = 0%)	18,018	55.5
Compacted shale	11,111	90
Uncompacted shale	7,692	130
Fresh water	5,291	189

$$\Delta t_{C(\mu sec/ft)} = \frac{1{,}000{,}000}{V_{C(ft/sec)}}$$

Confusing terminology!

- Velocity = "fastness"
  - The larger the number, the faster the formation
  - The smaller the number, the slower the formation
- Interval transit time (Dt) = "slowness"
  - The larger the number, the slower the formation
  - The smaller the number, the faster the formation
-

$$\Delta t \propto \frac{1}{\text{velocity}} \qquad \text{"slowness"} \propto \frac{1}{\text{"fastness"}}$$

Body waves: compressional waves

- Wylie Time-Average Equation for porosity

$$\Phi_{SONIC} = \frac{\Delta t_C - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}}$$

- Dt_C = interval transit time (measured by tool)
- Dt_{ma} = interval transit time of matrix (assumed)
- Dt_{fl} = interval transit time of fluid (assumed)

Matrix travel time parameter (Δt_{ma})

- Interval transit time (Dt) of the solid rock matrix
- Parameter entered by log analyst or petrophysicist
- Commonly assumed matrix travel times (Dt_{ma})

  Sandstone:55.5 msec/ft
  Limestone: 47.6 msec/ft
  Dolomite: 43.5 msec/ft

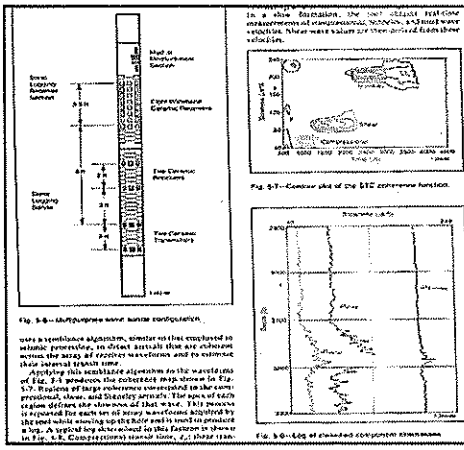
- Represent pure lithologies at zero-porosity

Fluid travel time parameter (Δt_{fl})

- **Interval transit time (Dt) of the pore fluid**
- **Parameter entered by log analyst or petrophysicist**
- **Commonly assumed fluid travel times (Dt_{fl})**

  Fresh water-based: 189 msec/ft
  Salt water-based: 185 msec/ft
  Oil-based: "205 msec/ft"

Air-drilled borehole: tool does not work in air!
Represents the fluid present within pores of the volume of investigation



SONIC LOG

C. The acoustic log ใช้ ϕ Porosity

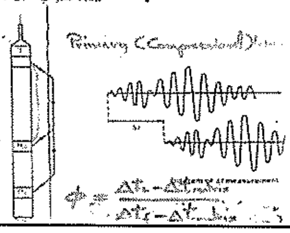
The basic principle is to record the traveltime (inverse of the veloc… that is propagated in the formation along the wall of the borehole betwee… receiver. The arrival of the fastest wave is detected (Fig. 8.22).

The complete recording of the wavetrain helps differentiate betwe… arrivals (compression, shear, mud, etc.).

There is a relationship between the traveltime and the porosity. Th… on a scale in microseconds per foot (Fig. 8.23).

Other applications of the acoustic log are possible:
- to study fracturing, LSS, Array Sonic (AMS)
- to add further information to geophysical data, WST
- to check cement jobs, CBL
- to evaluate formation permeability.
- Secondary $\phi_2 = \phi_T - \phi_{sonic}$

$$\Delta t_{log} = \phi \Delta t_f + (1-\phi)\Delta t_{ma}$$



$$\phi = \frac{\Delta t_L - \Delta t_{matrix}}{\Delta t_f - \Delta t_{matrix}}$$

Table 1

	v_{ma} (ft/sec)	Δt_{ma} (μs/ft)	Δt_{ma} (μs/ft) (commonly used)	Shale
Sandstones	18,000-19,500	55.5-51.0	55.5 or 51.0	86
Limestones	21,000-23,000	47.6-43.5	47.5	90
Dolomites	23,000	43.5	43.5	75
Anhydrite	20,000	50.0	50.0	100
Salt	15,000	66.7	67.0	
Casing (iron)	17,500	57.0	57.0	

น้ำจืด 189 μs/ft 250

Porosity Determination (Wyllie Time-Average Equation)

Consolidated and Compacted Sandstones

After numerous laboratory determinations, M.R.J. Wyllie proposed, for clean and consolidated formations with uniformly distributed small pores, a linear time-average or weighted-average relationship between porosity and transit time:

$$t_{LOG} = \phi\, t_f + (1-\phi)\, t_{ma} \quad \text{(Eq. 5-1a)}$$

or

$$\phi = \frac{t_{LOG} - t_{ma}}{t_f - t_{ma}} \times \frac{1}{C_p} \quad \text{(Eq. 5-1b)}$$

where

t_{LOG} is the reading on the sonic log in μs/ft. $C_p = \frac{\Delta t_{sh} \times C}{100}$

t_{ma} is the transit time of the matrix material.

$C = 1$ หรือ B_p

TABLE 3–6. Commonly used matrix and fluid velocities and acoustic transit time

Component	V_{ma} (ft/sec)	Δt_{ma} (μsec/ft)	Commonly Used Δt_{ma} (μsec/ft)
Quartz	18,000	55.6	55.6
Sandstone	18,000–19,500	55.5–51.0	50.6
Limestones	21,000–23,000	47.6–43.5	47.6
Dolomites	23,000	43.5	43.5
Anhydrite	20,000	50	50.0
Salt	15,000	66.7	67.0
Fluids	**V_f (ft/sec)**	**Δt_f (μsec/ft)**	**Commonly Used Δt_f (μsec/ft)**
Water (20% NaCl)	5,300	189	189
Water (15% NaCl)	5,000	200	200
Water (10% NaCl)	4,800	208	208
Water (pure)	4,600	218	218
Oil	4,200	238	238
Methane	1,600	626	626
Air	1,100	910	910

6. The sonic log should always be examined for cycle skipping. The cycle skipping results in th… acoustic log either spiking (sharp curve movements or too long a travel time being recorde… The cycle skipping often occurs in unconsolidated formations (particularly in gas-bearing zones… fractured formations, opposite gas-cut mud, or when the borehole is too large (over 12 to … in.) and the tool is still centered in the borehole. The cycle skipping may also occur becau… of bad or weak receiver or transmitter.

Example 3–13. Calculate the sonic porosity at a depth of 5,590–5,602 ft from the sonic given in Figure 3–41. Assume that Δt_f = 189 μsec/ft and Δt_{ma} = 55.5 μsec/ft. The shale zone 5,574–5,580 ft with Δt_{sh} = 111.5 μsec/ft shows that the formation is uncompacted.

Solution:

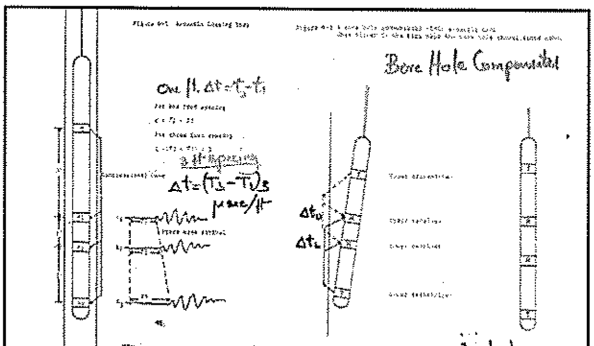
$$\Delta t_{LOG} = 107 \ \mu sec/ft \quad @5{,}590\text{–}5{,}602 \text{ ft}$$

$$C_p = \frac{\Delta t_{sh}}{100} = \frac{111.5}{100} = 1.115$$

=111.5/100=1.115

$$\phi_s = \frac{\Delta t_{LOG} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{1}{C_p} = \frac{107 - 55.5}{189 - 55.5} \times \frac{1}{1.115}$$

Bore Hole Compensated



1. Primary (Compressional)
2. Secondary (Shear)
3. Stonley Wave

$$\Delta t = \Delta t_f \phi + \Delta t_m (1-\phi)$$

$\Delta t_U = T_{U1} - T_{U2}$ จากด้านบน

$\Delta t_L = T_{L1} - T_{L2}$ จากด้านล่าง

$$\Delta t = \frac{\Delta t_U + \Delta t_L}{2}$$

Figure 6-3 Bore hole enlargement effects on acoustic logs (courtesy Schlumberger)

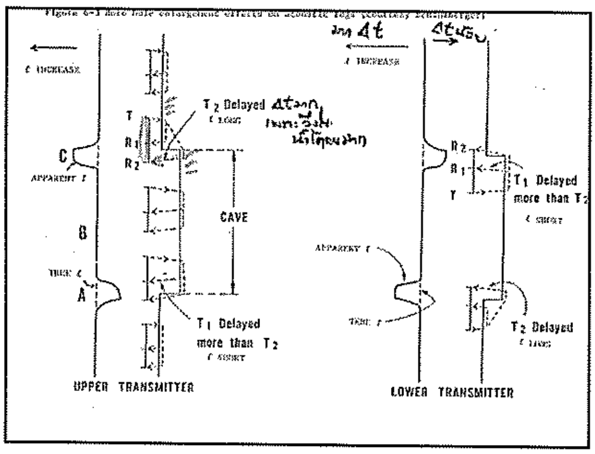


Figure 6-9 Porosity from the acoustic log

Ex. 6.1

$\Delta t_{sh} = 120$ μs/ft

in gas Sand

$\Delta t = 110$ μs/ft

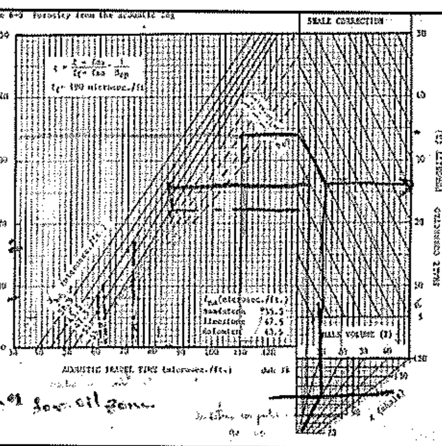
$B_{cp} = \frac{120 \times 1}{100} = 1.2$

$\phi = 34\%$

in gas

$\phi_c = 34 \times 0.7 = 24\%$

$\phi_c = 34 \times 0.9 = 30.6$ for oil zone



... The caliper and SP were run with the sonic log. The bit size appears to be about 9 inc... The caliper diameter less than bit size are indications of mudcake which show the permeable zones. The SP and caliper both pick out the permeable zones. The SP has bimetalism effects on it due to the SP being run with the sonic log. When bimetalism effects the SP it tends to follow the resistivity curves. Shales have low resistivity, see 8400, and thus these SP excursions are not indicative of the formation permeability. The back-up or off scale follow ups on the resistivity curves are always a change in sensitivity of 10. Thus when the curves go off on this example in intervals A, B and C the scales that follow are higher by a factor of 10 or 0-500 scales. Some representative depths and zones have been calculated to show how it is done. The example should not be considered to be anything more than a calculational example as in a real case all zones would be calculated.

	Depth	Rind	t	permeable?	why?	ϕ%	Sw%	SP Caliper
1	8444-48	22	84	yes	SP and caliper	26	11*	
2	8450	150	50.5	no	SP, Caliper ϕ	2.1	52*	
3	8456-58	17	70	yes	SP and caliper	16	20	
4	8474-76	5	69	yes	SP and caliper	15	40	
5	8491-93	2.5	68	yes	SP and caliper	14	61	Hole < bit

* Sw is probably off. Should probably be around 100% but resistivity and porosity could be off as resistivity is high and bed thin.
Zones 1, 3 and 4 will produce (1). Zone 5 will probably produce some water although without a test it is difficult to tell. Zone 2 will probably produce nothing as the porosity is too low to be permeable and all indicators say it is not permeable.

Ex. 6.2 F = ... = 14.79 Sw ... = 0.11

Sonic Log Corrections

1. Uncompacted Formation

$$\phi = \frac{\Delta t - \Delta t_{ma}}{t_f - t_{ma}} \cdot \frac{1}{C_p}$$

$$C_p = \frac{\Delta t_{sh}}{100}$$

Ex. 6-1 ; $\Delta t = 110$ μsec, $\Delta t_{sh} = 120$

$$C_p = \frac{120}{100} = 1.2$$

$$\phi = \frac{110 - 55.5}{190 - 55.5} \times \frac{1}{1.2} = 0.34$$

2. Hydro Carbon Zone.

in Gas ; $\phi = \phi(cal) \times 0.7$

in Oil ; $\phi = \phi(cal) \times 0.9$

Ex. 6-1. if in gas zone

$$\phi = 0.34 \times 0.7 = 0.24$$

3. Shaly Sand

$\phi_{...} = \phi_{...} - V_{sh}\phi_{...}$ ...

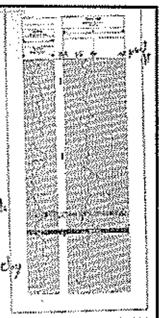
Compaction Factor

Laminated Shale

Dispersed Clay

Gas

Oil



THE GAMMA RAY TOOLS

THE GAMMA RAY IS NOT A POROSITY TOOL - HOWEVER, IT IS USU... RUN IN COORDINATION WITH POROSITY TOOLS AND IT IS VERY HEL... IN INTERPRETING POROSITY MEASUREMENTS.

I. PRINCIPLE:

THE GAMMA RAY TOOL MEASURES THE NATURAL RADIOACTIVITY OF THE FORMATIONS. RADIOACTIVE ELEMENTS LIKE POTASSI... TEND TO CONCENTRATE IN SHALES. THESE ELEMENTS EMIT NATURAL GAMMA RAYS WHICH CAN BE EASILY MEASURED BY MEANS OF A GEIGER MULLER COUNTER OR A SCINTILLATION DETECTOR. GEIGER COUNTER

ON THE OTHER HAND, CLEAN RESERVOIR FORMATIONS LIKE SANDSTONE, DOLOMITE OR LIMESTONE USUALLY HAVE A VERY LOW LEVEL OF NATURAL RADIOACTIVITY.

BY RECORDING THE NUMBER OF GAMMA RAYS EMITTED BY THE FORMATION THE GAMMA RAY TOOL THEREFORE ALLOWS EASY DISTINCTION BETWEEN CLEAN RESERVOIR ROCKS AND SHALES.

FURTHERMORE, IF A SMALL QUANTITY OF SHALE IS PRESENT IN THE RESERVOIR ROCK, THE NUMBER OF GAMMA RAYS MEASURED ALLOWS A QUANTITATIVE EVALUATION OF THE PERCENTAGE OF SHALE CONTAINED IN THE FORMATION.

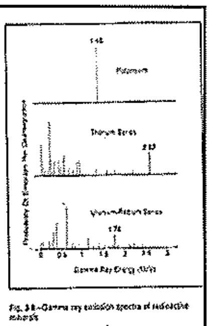
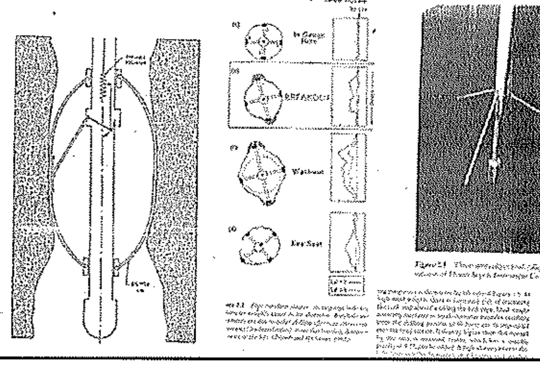


Fig. 3.8—Gamma ray emission spectra of radioactive minerals

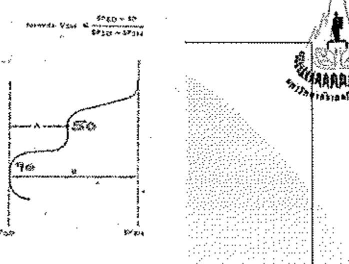
CALIPER :

Range : 2-30 in., Accuracy : ... in.
Resolution : 0.1 in.



SPONTANEOUS POTENTIAL

$$V_{sh} = 1 - \frac{PSP}{SSP}$$

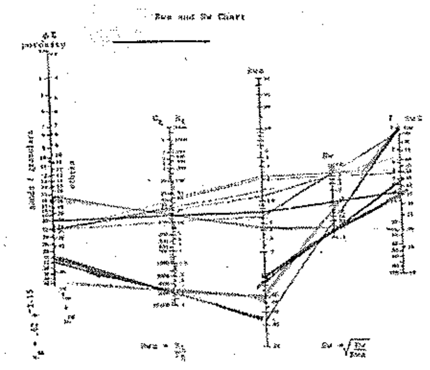


$$V_{sh} = 1 - \frac{50}{90} = \frac{40}{90}$$

GOOD V_{sh} - THICK ZONES
- WATER BEARING
- GOOD SP DEFLECTION
- LAMINATED SHALE

Figure 7-6 Solution of water saturation equation ...

Rwa and Sw Chart



Example: Porosity is 20% in a sandstone. Rt is 15. These give you an Rwa of 0.22. If Rw is .09, then Sw = 56%.

Fig 9.10 Classification of Resistivity Log

TABLE 3-1. Classification of resistivity logs

Flushed Zone (R_{xo})	Invaded Zone (R_i)	Uninvaded Zone (R_t)
Microlog	Short Normal	Long Normal
Microlaterolog	Laterolog-8 (LL8)	Laterolog
Proximity Log	Spherically Focused Log (SFL)	Deep Induction Log
Microspherically Focused Log (MSFL)	Medium Induction	Deep Laterolog (LLD)
	Shallow Laterolog (LLS)	Laterolog-3 (LL3)
		Laterolog-7 (LL7)
		Induction Log (6FF40)

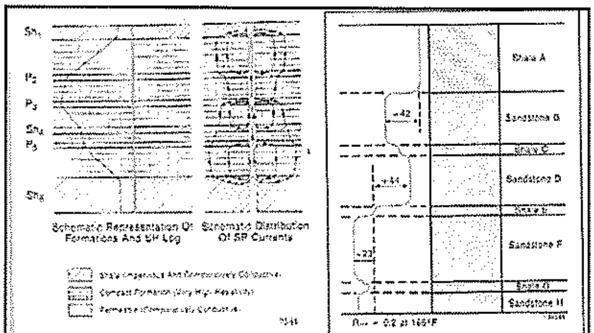
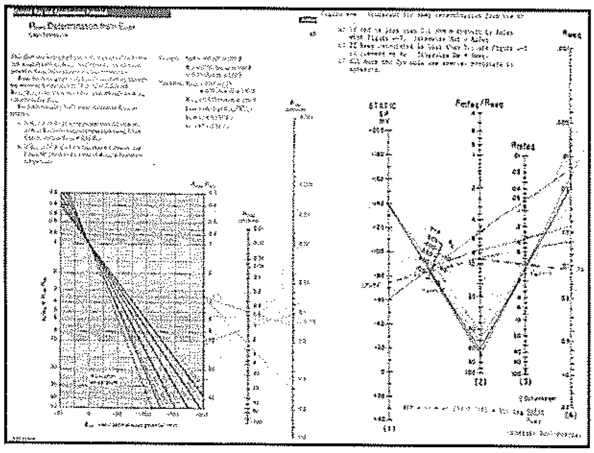
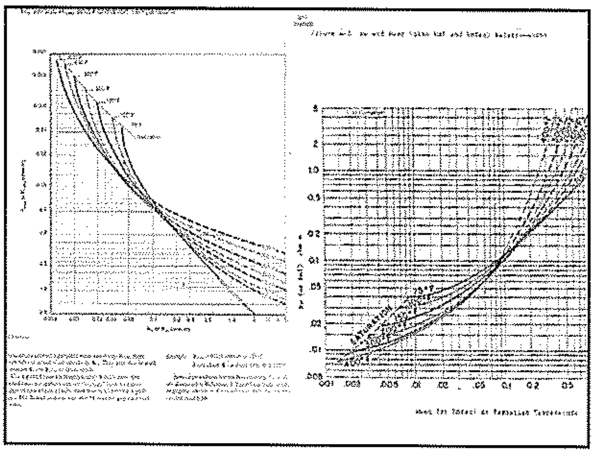


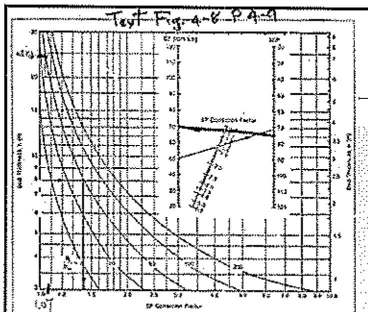
Fig. 3-4—Schematic representation of SP phenomena highly resistive formations

Fig. 3-5—SP baseline shift





Text Fig 4-8 P 4-9



CHAPTER 6 PROBLEMS

1. On problem log 6-1 which is a Strawn Sandstone from Clay County, Texas, mark the permeable sections, calculate Rw from the SP, and calculate the water saturation for 3580-90, 3604-14 and 3634-36. Mark the pay zones and the water zones, if any. Is 3632-40 a sandstone. Why?

2. On problem log 6-2 determine the porosity for the four marked zones. Determine the water saturation for the four marked zones. Are the pay zones gas or oil zones and why? What is the pay thickness of each zone?

3. Calculate the **HW NO 6, SONIC LOG** travel times assuming

Do problem chapter 6; 6.1, 6.2 in HILCHIE TEXT

and Chapter10; 10.6, and 10.9 in SPE TEXT

travel times ...

4. An uncompacted formation has a shale travel time of 125 microsec/ft, a formation travel time of 112 microseconds/ft. What is the porosity of the formation if the zone is a water zone, oil zone or gas zone?

5. Draw a gamma ray and SP for a sequence of thick formations which are from top to bottom, a shale, permeable sandstone, a shale, a impermeable limestone, a shale, a permeable limestone, an impermeable limestone, a permeable limestone and a shale.

HW NO 6, SONIC LOG
Do problem chapter 6; 6.1, 6.2 in HILCHIE TEXT and Chapter10; 10.6, and 10.9 in SPE TEXT
Due date: Friday 15 February 2013

0.6 Fig. 10.34 shows a section of the induction/electrical log, 3-ft-span sonic log of a well in south Texas. Fluid contacts are also shown. The high-resistivity peaks are caused by streaks of limestone.

a. Explain the spikes displayed in Zone E.

b. The average core porosities of Zones A through D are 33%, 32%, 34%, and 31%, respectively. Calculate the log porosities of these zones and compare them with those of the cores. Experience with these sediments indicates a compaction correction factor of 1.44.

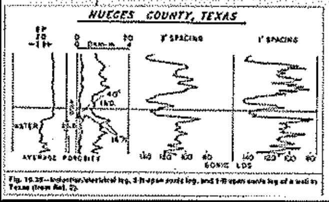


Fig. 10.35—Induction/electrical log, 3-ft-span sonic log, and 1-ft-span sonic log of a well in Texas (from Ref. 2).

Chapter 10

Problem 10.3 $\phi_e = 36\%$.
Problem 10.4 $R_{xo} = 1.2$.
Problem 10.6 a. Cycle skipping.
b. Log porosities of Zones A and B and agree with core porosities. Log porosities of Zones C and D are affected by the presence of gas in the formation.
Problem 10.7 a. The 3-ft spacing sonic tool.
b. The lower the porosity, the deeper the invasion and the higher the reading of the 16-in. Normal tool.
Problem 10.9 The porosity of Zone 2 is estimated at 11%.
Problem 10.10 The intervals 4,220 to 4,360 ft and 4,400 to 4,480 ft contain zones of altered shales.

10.9 Fig. 10.37 shows induction/electric and sonic logs of the Morrow sand of Oklahoma. Estimate the porosity of the five Zones 1 through 5 marked on the log.

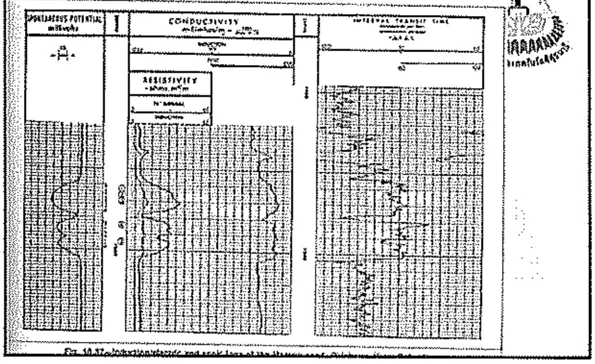


Fig. 10.37—Induction/electric and sonic logs of the Morrow sand, Oklahoma.

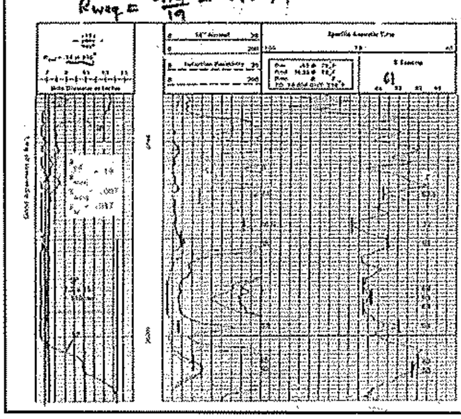
QUANTITATIVE ANALYSIS PART I

CHAPTER7

1. CORRELATE ϕ (Δt) & Rt Logs.
2. PICK OUT PERMEABLE BEDS use SP or Ri/Rt, gamma.
3. MARK ZONES ON Rt Log. Ra
   Correct for thin bed or Invasion (Fig 5-9) DIL, 3-7, 3-9 Rt (Fig 11-4) DLL
4. MARK ZONES ON ϕ Log and Cal. ϕ
   Sonic Fig 6-9 or eq 6.2 } also density-neutron
   Density Fig 8-4 or Eq. 8-1 } acoustic-neutron Crossplots
5. Calculate Rwa Fig 2-6 Eq. 2-6, 3-7, 7-2, 2-8 $R_{wa} = \frac{Rt}{Fr}$, $\frac{1}{\phi^2}$
6. Lowest Rwa exhibits Rw
7. Calculate Rw from SP, use Fig 4-4 and 4-5
8. Where agreement is poor, select the lowest Rwa, Rw
9. All zones where Rwa > 3 Rw are potentially Hydrocarbon.
10. Cal. Sw. Fig 2-6 or Eq 7-3 $Sw = \sqrt{\frac{R_w}{R_{wa}}}$
   $\left(R_{wa} = \frac{Rt}{F_R}\right)$ $= \sqrt{\ }$

$R_{waq} = \frac{0.14}{19} = 0.007$

$\frac{7.5}{\frac{1}{(.105)^2}} = 0.082$



$= \sqrt{\frac{0.017}{0.083}} =$

$= \sqrt{\frac{0.017}{0.47}}$

$\frac{1}{(.105)^2}$ $\phi = \frac{\Delta T - 47.5}{190 - 47.5}$

$S_w = \sqrt[n]{\frac{a}{\phi^m} \cdot R_w \cdot \frac{1}{R_t}}$

Saturation Exponent; Intercept; Measured Porosity; Cementation Exponent

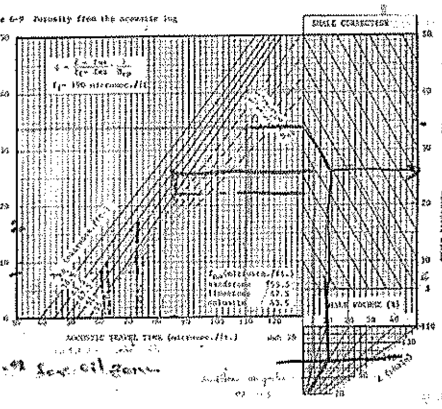
$= \sqrt{\frac{0.017}{0.083}} =$

$= \sqrt{\frac{0.017}{0.47}}$

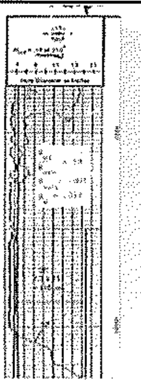
$F_R = \frac{1}{\phi^2}$ $S_w = \sqrt{\frac{R_w}{R_{wa}}}$ $R_{wa} = \frac{R_t}{F_R}$

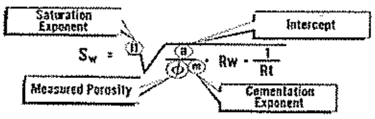
Rt	del T	$\phi = \frac{\Delta T - 47.5}{190 - 47.5}$	$F_R = \frac{1}{\phi^2}$	$R_{wa} = \frac{R_t}{F_R}$	$S_w = \sqrt{\frac{R_w}{R_{wa}}}$
7.5	62.5	0.11	90.25	0.083	0.45
16.5	72	0.17	33.83	0.488	0.19
38	61	0.09	111.42	0.341	0.22
1	68	0.14	48.32	0.021	0.91
1	66	0.13	59.33	0.017	1.00
1	68	0.14	48.32	0.021	0.91
3.5	58	0.07	184.18	0.019	0.95
65	52	0.03	1002.78	0.065	0.51
80	53	0.04	671.28	0.119	0.33

Figure 6-9 Porosity from the acoustic log



Ex. 6.1
$\Delta t_{sh} = 120$ μs/ft in gas sand
$\Delta t = 110$ μs/ft
$B_{cp} = \frac{(20 \times 1)}{100} = 1.2$
$\phi = 34\%$ in gas
$\phi_c = 34 \times 0.7 = 24\%$
$\phi_c = 34 \times 0.9$ for oil zone $= 31.6$





$$S_w = \sqrt[n]{\frac{a}{\phi^m} \cdot Rw \cdot \frac{1}{Rt}}$$

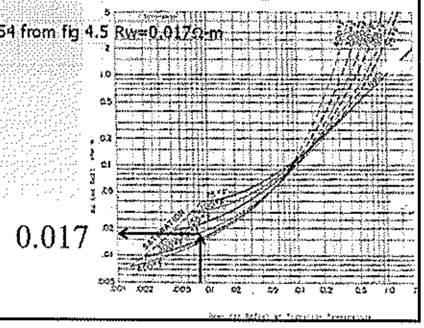
$$K = 60 + 0.133 \times T_f$$
$$= 60 + 0.133 \times 140 = 78.62$$
$$\log R_{weq} = \left[\frac{-75 + (78.62)\log(1.0)}{78.62}\right]$$
$$R_{weq} = 0.111$$

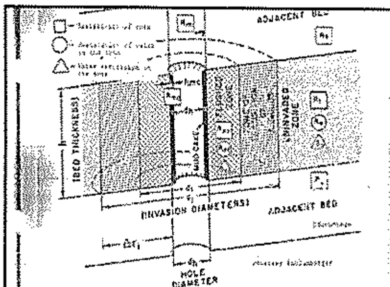
Rmf=0.36@80=0.145@210

K=60+0.133*210= 87.93

LOG(Rweq)=((-110+(88*log(0.145))/88= -2.08863

Rweq= 0.008154 from fig 4.5 Rw=0.017Ω-m





residual oil { $Sh_r = 1 - S_{xo}$ $Sh = 1 - S_w$

Movable oil } $Sh - Sh_r = 1 - S_{xo} - S_w$

CHAPTER 7 PROBLEMS

1. On example 7-1 the caliper shows mudcake as hole diameter less than bit size [illegible] which indicates that the zones with mudcake are permeable. The caliper is off depth. How far off depth is it. The SP was run with the sonic log and is showing some bimetallic effects. At what depth are these anomalies. Where is the oil water contact on this example?

2. Calculate the logs that comprise Problem Log 7-2 (a and b). Use the Rwa approach. What is the pay zone thickness, porosity and water saturation? If this well is on a [illegible] acre spacing what is the total amount of oil in place in the pay zone?

The SP on the acoustic log and the specific acoustic time curves are off depth. How much off depth are they? Why is the acoustic SP a little different than the induction SP? Which is right?

3. On Problem Log 7-3 calculate the logs using the Rwa approach. Determine porosity and water saturation.

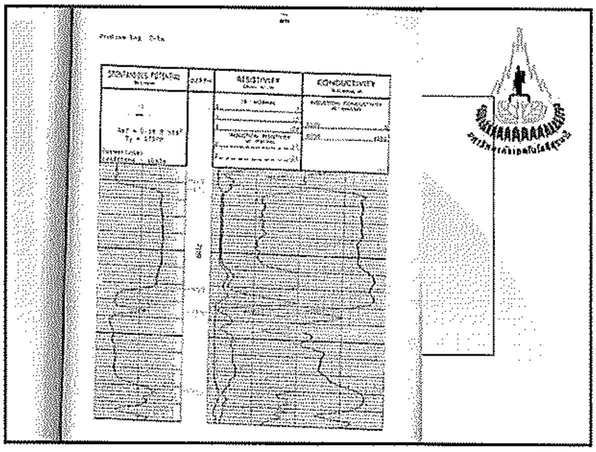
The shale travel time is [illegible] microsec/ft. How will this effect your calculational procedure?

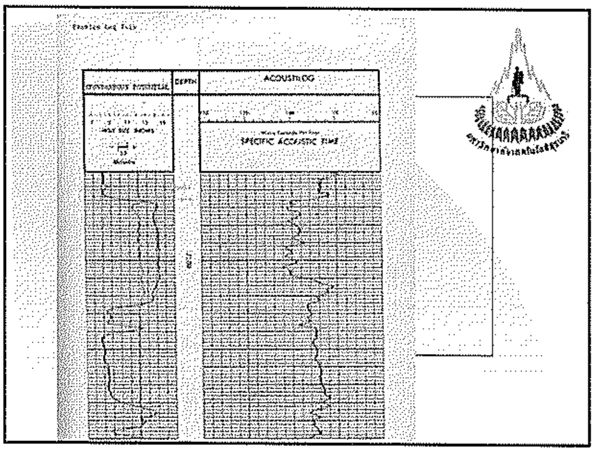
This is an oil bearing zone from South Louisiana. Why are the water saturations so different?

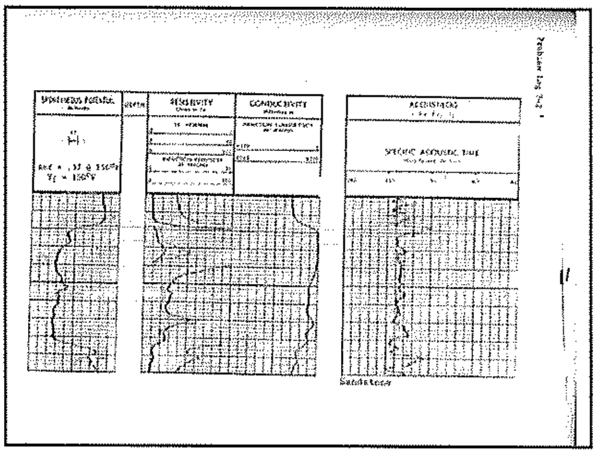
4. Problem Log 7-3 is a log over the [illegible] limestone. The SP and caliper are off the sonic log. This is one of the earlier induction electric logs (that is what the [illegible] means). Find the oil water contact. What will the tests at levels A and B produce?

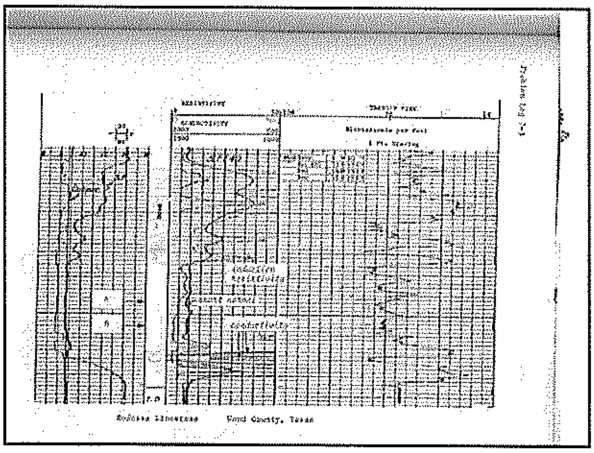
The bit size is 8 3/4 inches in diameter. How far off depth is the caliper log. The SP again exhibits bimetallics. At what depths do these effects occur.

NOTE: If you used the induction resistivity curves on some of these examples you may have missed the pay zones. A significant number of conversions from conductivity to induction resistivity are poor in the low resistivity range. I usually estimate 1 in 4 logs have bad resistivity / conductivity conversions.









HW NO 7; Rwa approach Chapter 7; 2 and 4 in HILCHIE TEXT and Chapter12; 12.3 in SPE TEXT and in the hand out sheet

Due Date; 22 FEBRUARY 2013

1. On example ... effects. At what depth are these ... Where is the oil water contact on ...

2. Calculate the logs that comprise Problem Log 7-1 (a and b). Use the Rwa approach. What is the pay zone thickness, porosity and water saturation? If this well is on a 40 acre spacing what is the total amount of oil in place in the pay zone?

   The SP on the acoustic log and the specific acoustic time curves are off depth. How much off depth are they? Why is the acoustic SP a little different than the induction SP? Which is right?

3. On Problem Log 7-2 calculate the logs using the Rwa approach. Determine porosity and water saturation.

   The shale travel time is 112 microsec/ft. How will this effect your calculational procedure?

   This is an oil bearing zone from South Louisiana. Why are the water saturations so different?

4. Problem Log 7-3 is a log over the Rodessa limestone. The SP and caliper are off the sonic log. This is one of the earlier induction electric logs (that is what the 5FF40 means). Find the oil water contact. What will the tests at levels A and B produce?

   The bit size is 8 3/4 inches in diameter. How far off depth is the caliper log. The SP again exhibits bimetalism. At what depths do these effects occur.

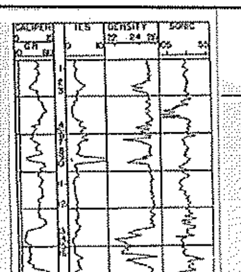


Fig. 12.23—Log data for Problem 12.3 (courtesy Schlumberger).

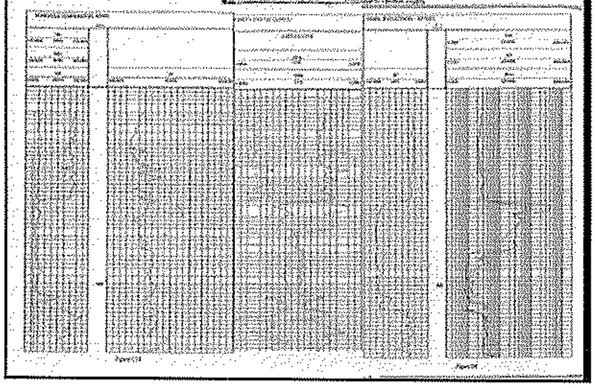
12.3 Induction/gamma ray, density, and sonic logs were recorded in oil-based mud of a U.S. gulf coast well that penetrates a sand/shale series. Tabulated below are log values for each of the levels numbered on the log of Fig. 12.23.

a. Calculate R_{wa} for each level using sonic log porosity.
b. Repeat the above calculations using density log porosity.
c. R_{wa} density differs slightly from R_{wa} sonic in certain zones (e.g., Zones 5, 6, 13, and 14). Explain the reason for this slight difference.
d. R_{wa} density differs drastically from R_{wa} sonic in Zones 1, 8, 11, 12, and 17. Explain the reason for this drastic difference.
e. What is the most probable value of formation water resistivity?
f. If the cutoff saturation is 50%, what are the probable pay zones?

Level	R_{IL} ($\Omega \cdot m$)	ρ_b (g/cm³)	Δt (μsec/ft)
1	2.6	2.51	77.5
2	4.8	2.32	81
3	4.0	2.33	79.5
4	5.0	2.345	79.5
5	4.0	2.39	79.5
6	5.0	2.41	79.5
7	5.8	2.24	87
8	3.0	2.49	82
9	11.0	2.32	79.5
10	10.0	2.27	82.5
11	1.65	2.50	90
12	2.3	2.53	79.5
13	1.8	2.26	83.5
14	1.25	2.195	90
15	1.75	2.32	87.5
16	1.50	2.22	87.5
17	1.25	2.49	94

Problem 12.3
a. Zone 10: $R_{wa} = 0.50\ \Omega \cdot m$.
b. Zone 10: $R_{wa} = 0.65\ \Omega \cdot m$.
c. The petrophysical models used to calcula[te] ... and F.
d. The zones are very shaly.
e. $R_w = 0.12\ \Omega \cdot m$.
f. Zones 7, 9, and 10.

HW no 7; Hard approach chapter 7; 2 and 4 in HILCHIE TEXT and Chapter12; 12.3 in SPE TEXT and in the hand out sheet



ROCK PROPERTY APPLICATIONS

GEOLOGICAL DETERMINATIONS

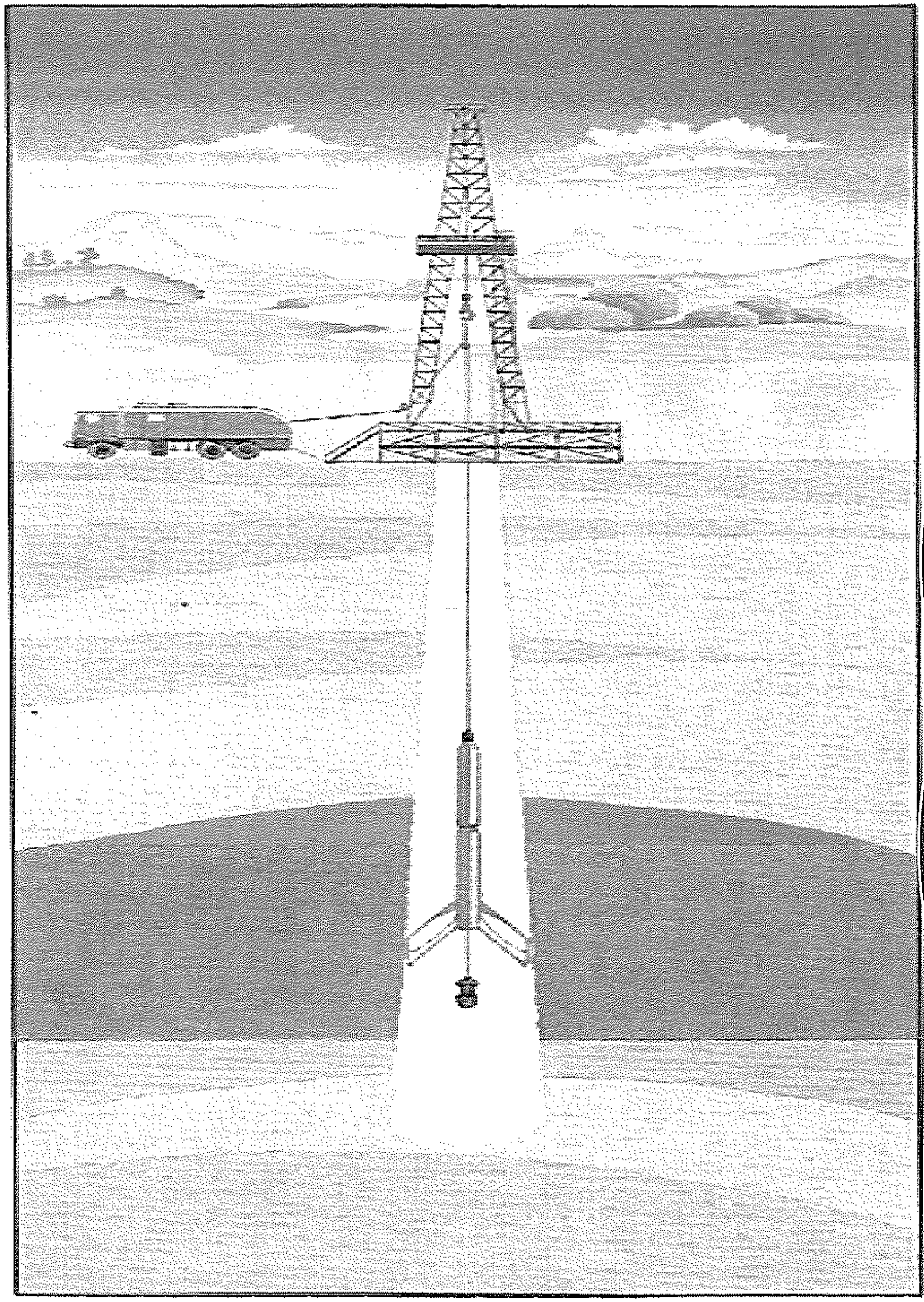


Fig. 1-2—Wireline logging operation.

WELLLOGGING

CHAPTER8
CHAPTER9

434359,505359 WELL LOGGING 2013(3/2555)

COURSE OUTLINES

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)

Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)

Resistivity Device(2 hrs.)

Spontaneous Potential (SP) Log(2 hrs.)

Induction Electric and Dual Induction Logs(2 hrs.)

Acoustic , Gamma Ray and Caliper Logs(2 hrs.)

Quantitative Analysis –Part I (2 hrs.)

Density, and Neutron Logs(3 hrs.)

Combined Porosity and Lithology logs Determinations(2 hrs.)

Focused Resistivity Logs (2 hrs.)

Openhole Log and QUICKLOOK Interpretations(3 hrs.)

Shaly Sand Interpretations(3hrs.)

Case Hole Logging(3 hrs.)

Computer Processing of well Logs(1 hr.)

Fracture Detection with Well Logs(1 hr.)

TEXT BOOKS

DOUGLA W. HILCHIE , *APPLIED OPENHOLE LOG INTERPRETATION*, (for Geologists and Engineers) Revised 1982.

REFERENCES

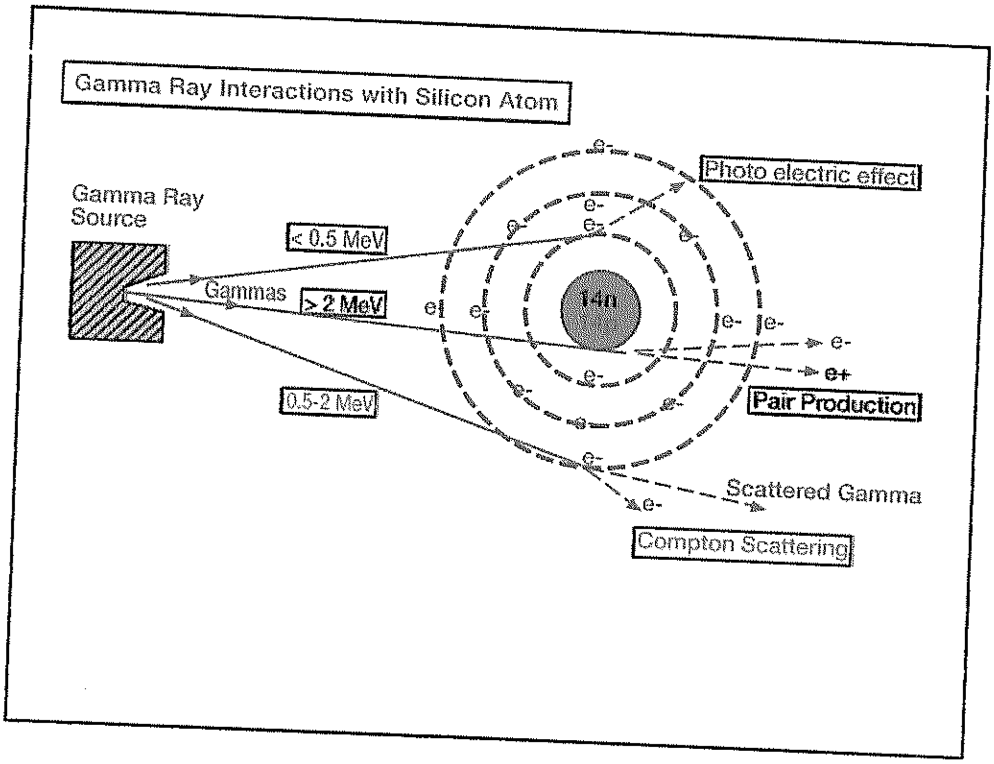
Schlumberger , ' LOG INTERPRETATION PRINCIPLES/APPLICATIONS " 1989

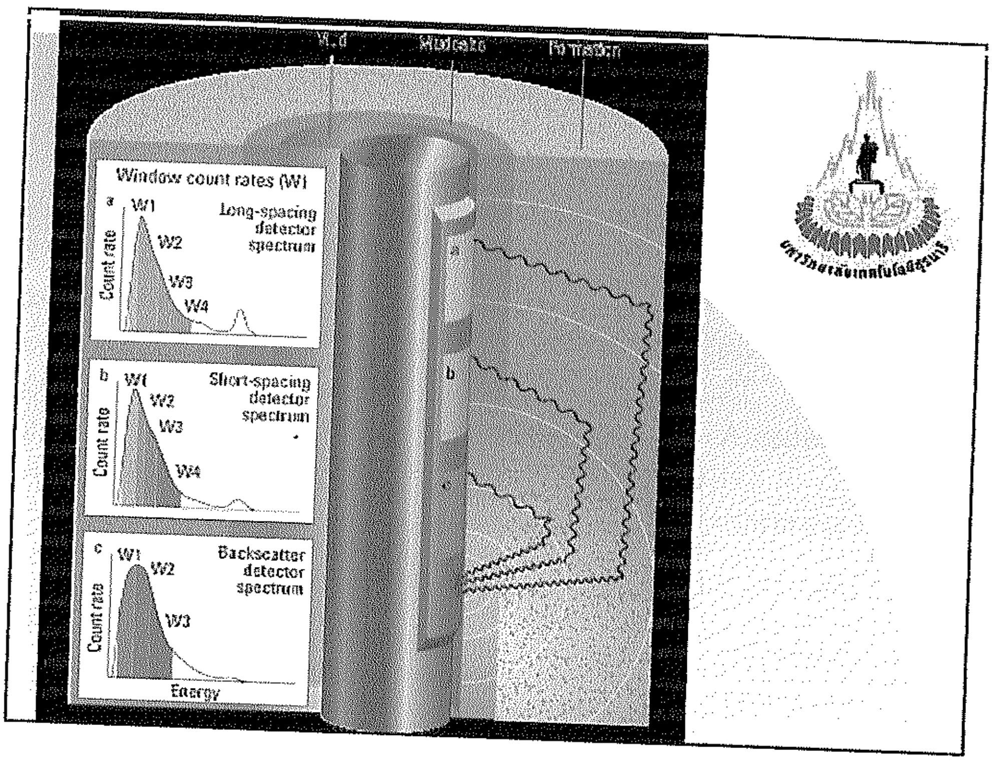
M. A. MIAN, " PETROLEUM ENGINEERING Handbook for the Practicing Engineer ', Volume I, PennWell Books , 1992

Petro Canada " Fundamentals of Core Analysis and Special Core Analysis', PTT.EP. Training, 1988.

GRADING

Homework	20 %
Quiz I, II	20 %
Mid Term	25 %
Final Exam	35 %


Gamma Ray Interactions with Silicon Atom
Gamma Ray Source
Gammas
< 0.5 MeV
> 2 MeV
0.5-2 MeV
14n
e-
e+
Photo electric effect
Pair Production
Scattered Gamma
Compton Scattering


Formation
Window count rates (W)
a
W1
W2
W3
W4
Long-spacing detector spectrum
Count rate
b
Short-spacing detector spectrum
c
Backscatter detector spectrum
Energy

434356 PRODUCTION ENGINEERING II 3/2554(2012)
QUIZ NO 1@B1214(Tuesday; Feb. 14, 2012, 21.00-23.00, 2 hrs. 75 points(15%), only one A-4 SHEET and calculators are allowed)

1. (a) Explain briefly what **resource management** is. (4 points)
   (b) Explain briefly why we need sequencing the fields in offshore production. (4 points)
   (c) Explain briefly what types of control valves are. (4 points)
   (d) Explain briefly what artificial lifts are being used in Thailand. (4 points)
   (e) Explain briefly what three types of Christmas trees are. (4 points)

2. Construct a chart of gas flow rate versus pressure ratio (P2/P1) for choke diameters (bean size) 32/64 of an inch. Assume that the choke flow coefficient is 0.85 the gas gravity is 0.7, γ is 1.25, and the wellhead temperature is 120° F. Calculate gas flow rate when the flowing tubing head pressure P1varies from 100-1000 psia, and assumed P2=100 psia. Assume that the choke flow coefficient is 0.85 the gas gravity is 0.7, γ is 1.25, **(25 points) Given;**

$$\left(\frac{p_2}{p_1}\right)_{critical} = \left(\frac{2}{\gamma+1}\right)^{\gamma/(\gamma-1)}$$

$$q_g = 3.505 D_{64}^2 \left(\frac{P_1}{P_{sc}}\right) \alpha \sqrt{\left(\frac{1}{\gamma_g T_1}\right)\left(\frac{\gamma}{\gamma-1}\right)\left[\left(\frac{P_2}{P_1}\right)^{2/\gamma} - \left(\frac{P_2}{P_1}\right)^{(\gamma+1)/\gamma}\right]}$$

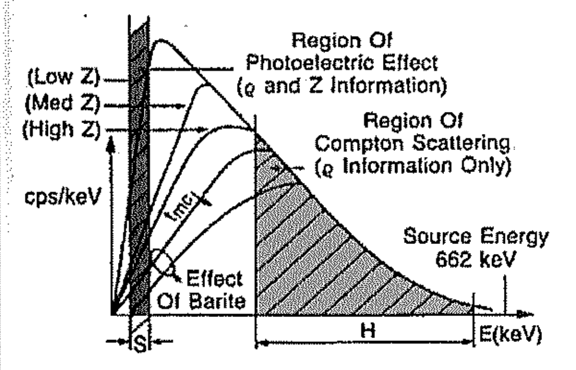
3. Design both vertical and horizontal separator to separate 6,000 BPD of crude oil (48°API, S.G = 0.788) from the gas (M.W= 21) of 80 MMSCF/D at the separator condition pressure of 200 psia temperature of 120° F(z = 0.97). Given; the standard condition at 14.7 psia 60° F. The oil residence time is 2 min, and for horizontal separator, design $A_g = ¾\ A_{sep}$.. The design ratio of length / diameter should be 2- 3. (Given; F_{co} = 0.167for a vertical and=0.382 for a horizontal separator) (30 points)

$$\rho_g = \frac{M.W.P}{ZRT}, \rho_o = \gamma_o \times 62.4 \frac{lb}{ft^3}, \ V_0 = 0.0039 q_0 (B/d) \times t(\min)$$

$$q_g = \frac{Volume}{time} = \frac{Q(SCF/D)}{24\times 60\times 60} \times \frac{14.7}{p_{sep}} \times \frac{zT_{sep}}{520} \qquad U_{\max} = 0.382\left(\frac{\rho_o - \rho_g}{\rho_g}\right)^{0.5} ft/\sec$$

$$q_g = 86,400 A_g F_{co} \frac{p(T_{sc}+460)}{zp_{sc}(T+460)}\left(\frac{\rho_L - \rho_g}{\rho_g}\right)^{1/2}$$

Figure 2: Energy Spectrum for measuring Compton Scattering and Photoelectric Absorption



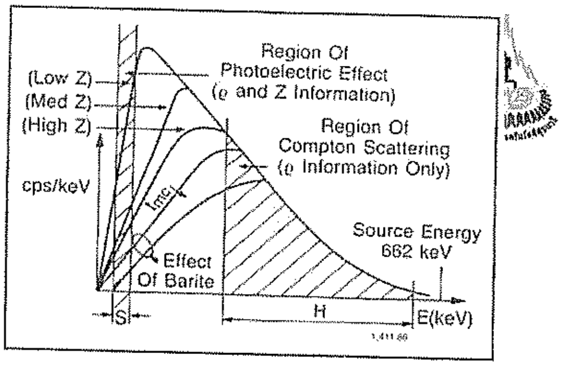
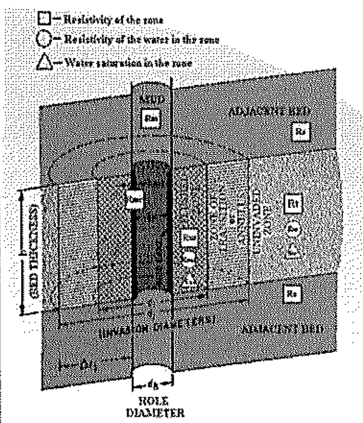
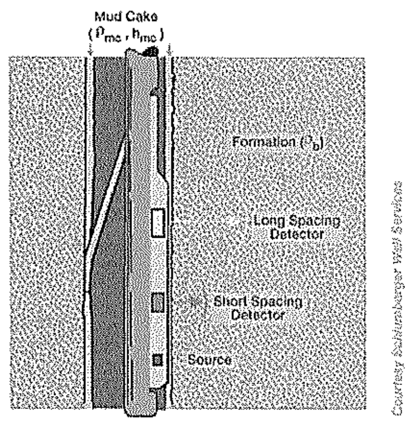


Fig. 5-19—Variations in spectrum for formation with constant density but different Z.



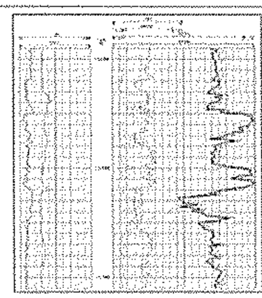


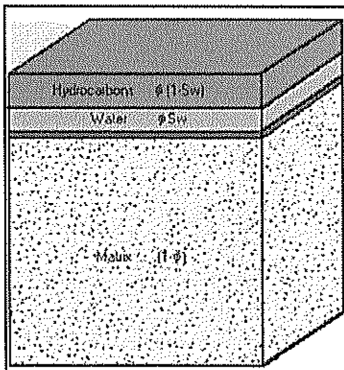
Density Porosity
Formula

- Formation bulk density (ρ_b) is a function of matrix density (ρ_{ma}), porosity and formation fluid density (ρ_f)
- Density porosity is defined as:

$$\phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

- The matrix density and the fluid density need to be known





Porosity From Density Log

ϕSw Fractional amount of water per unit volume

ϕ(1-Sw)Fractional amount of hydrocarbons per unit volume

Density Log

Porosity

$$\begin{Bmatrix}\text{Measured} \\ \text{bulk density}\end{Bmatrix} = \begin{Bmatrix}\text{matrix} \\ \text{contribution}\end{Bmatrix} + \begin{Bmatrix}\text{pore fluid} \\ \text{contribution}\end{Bmatrix}$$

$$\rho_b \quad = \quad (1-\phi)\rho_{ma} \quad + \quad \phi\rho_f$$

or

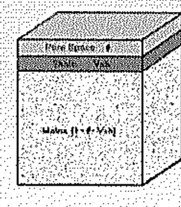
$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

where $\rho_{ma} \equiv$ matrix density

$= 2.65$ for ss

$= 2.71$ for lms

$= 2.86$ for dolo



Volume of Shale calculations:

A shaly formation is depicted in Figure 7a. If Vsh is the fractional volume of shale then the fractional volume of matrix is (1-Vsh-f) and:

RHOB = (1-Vsh-f)*RHOMA + Vsh*RHOSH + PHI*RHOF

and

PHI = (RHOMA-RHOB)-Vsh*(RHOMA-RHOsh

(RHOMA-RHOF)

and

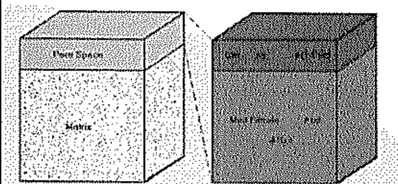
Vsh = (RHOMA-RHOB)-PHI*(RHOMA-RHOF)

(RHOMA-RHOsh)

Shale effectively reduces the measured porosity on both the Density tool and the Neutron tool by:-

PHID = PHIeff + PHIDsh(Vsh)

PHIN = PHIeff + PHINsh(Vsh)



Gas Effects:

Figure 7b illustrates a gas bearing formation

RHOB = (1- PHI)*RHOMA + PHI*Sxo*rmf + PHI*(1-Sxo)*RHOg and

$$\boxed{\rho_b = (1-\varphi)\rho_{ma} + \phi S_{XO}\rho_{mf} + \phi(1-S_{XO})\rho_h}$$

$\rho_f = S_{xo}\rho_{mf} + (1-S_{xo})\rho_h$ --(8-2)

$= \left(\sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}\right)\rho_{mf} + \left(1-\sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}\right)\rho_h$

$$\boxed{\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_h - (\rho_{mf} - \rho_h)S_{XO}}}$$

PHI = (RHOMA -RHOB)/[RHOMA -RHOG-(RHOmf-RHOg)*Sxo]

$$\boxed{S_{XO} = \sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}}$$

An approximation phiorrg (in g/cc) can be given by: -

RHOg = 0.18/[(7644/D) + 0.22] where D = depth in feet

Density Log

Porosity

- Define ρ_f as average density of fluid in pore space
- Depth of investigation of density tool is shallow (invaded zone), thus

$$\rho_f = S_{xo}\rho_{mf} + (1-S_{xo})\rho_h$$

- In practice,

Mud Type	ρ_{mf} (gm/cc)
oil	0.9
Fresh water	1.0
Salt water	1.1

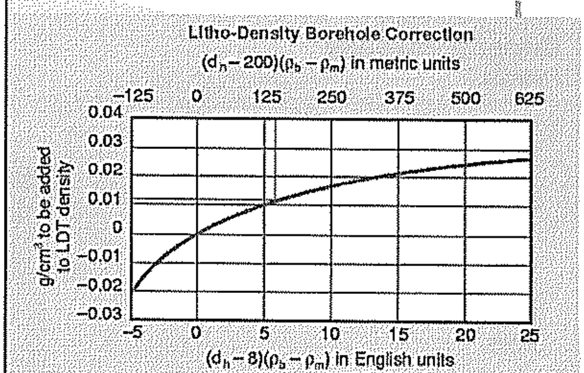
$\rho_f = S_{xo}\rho_{mf} + (1-S_{xo})\rho_h$

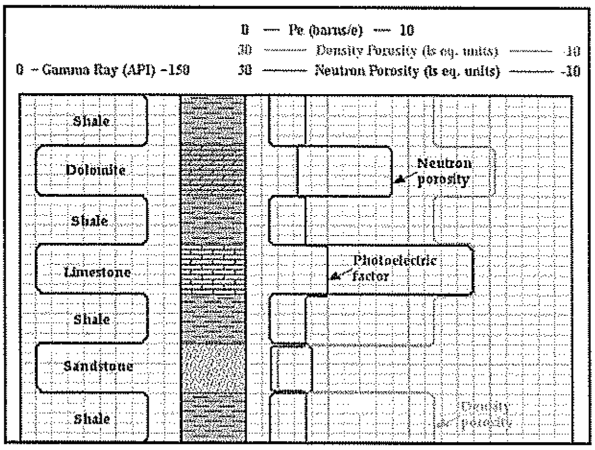
$= \left(\sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}\right)\rho_{mf} + \left(1-\sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}\right)\rho_h$

- In water-bearing zones, $S_{xo} = 1$ and $\rho_f = \rho_{mf}$

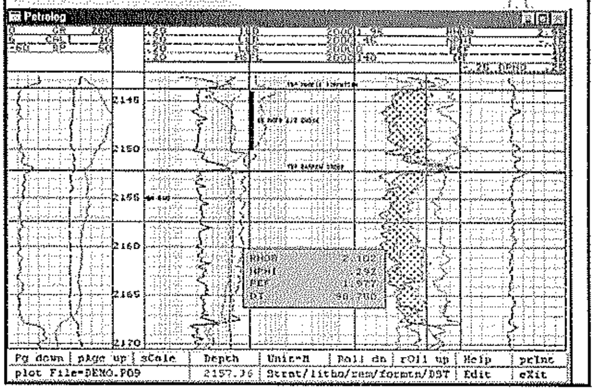
$$\boxed{\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_h - (\rho_{mf} - \rho_h)S_{XO}}} \quad \boxed{S_{XO} = \sqrt{\frac{0.81}{\phi^2}\cdot\frac{R_{xo}}{R_t}}}$$

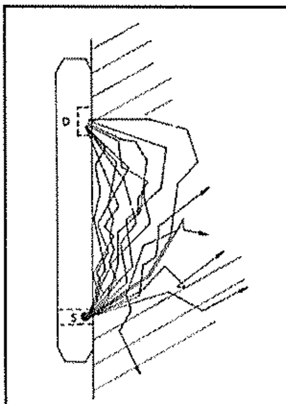
- In oil-bearing zones, use same $\rho_f = \rho_{mf}$ Assumes S_{xo} is large and $\rho_h \approx \rho_{mf}$



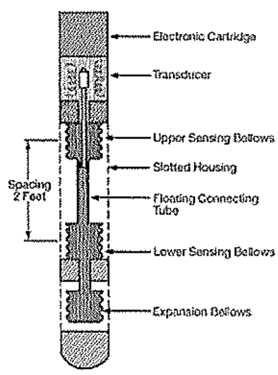


- Figure 6: Typical Density/Neutron Log Presentation





Gamma Ray Backscattering
(From Tittman and Wahl, Geophysics, April 1965)



DENSITY LOG

Table 5-2

Element	A	Z	$2\frac{Z}{A}$
H	1.008	1	1.9841
C	12.011	6	0.9991
O	16.000	8	1.0000
Na	22.990	11	0.9569
Mg	24.320	12	0.9868
Al	26.980	13	0.9637
Si	28.090	14	0.9968
S	32.070	16	0.9978
Cl	35.460	17	0.9588
K	39.100	19	0.9719
Ca	40.080	20	0.9980

For liquid-filled sandstones, limestones, and dolomites the tool reading, ρ_a, is practically identical to actual bulk density, ρ_b. For a few substances, such as sylvite, rock salt, gypsum, anhydrite, coal, and gas-bearing formations, the corrections shown in Fig. 5-15 are needed to obtain bulk density values from the density log readings.

Porosity From Density Log

For a clean formation of known matrix density, ρ_{ma}, having a porosity, ϕ, that contains a fluid of average density, ρ_f, the formation bulk density, ρ_b, will be:

$$\rho_b = \phi\,\rho_f + (1-\phi)\,\rho_{ma}. \quad \text{(Eq. 5-7a)}$$

For usual pore fluids (excepting gas and light hydrocarbons) and for common reservoir matrix minerals, the difference between the apparent density ρ_a, read by the density log, and the bulk density, ρ_b, is so trivial that it is disregarded. Solving for ϕ,

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad \text{(Eq. 5-7b)}$$

where $\rho_b = \rho_a$ (with exceptions noted).

Common values of ρ_{ma} are given in Table 5-3.

The fluid in the pores of the permeable formations, within the relatively shallow zone investigated by the tool (about 6 in.), is usually mostly mud filtrate. This mud filtrate may have a density ranging from slightly less than 1 to more than 1.1 depending upon its salinity, temperature, and pressure. Fig. 5-16 shows the densities

Table 5-3

Compound	Formula	Actual Density ρ_b	$\frac{2\Sigma Z's}{Mol.\ Wt.}$	ρ_e	ρ_a (as seen by tool)
Quartz	SiO_2	2.654	0.9985	2.650	2.648
Calcite	$CaCO_3$	2.710	0.9991	2.708	2.710
Dolomite	$CaCO_3MgCO_3$	2.870	0.9977	2.863	2.876
Anhydrite	$CaSO_4$	2.960	0.9990	2.957	2.977
Sylvite	KCl	1.984	0.9657	1.916	1.863
Halite	NaCl	2.165	0.9581	2.074	2.032
Gypsum	$CaSO_4 2H_2O$	2.320	1.0222	2.372	2.351
Anthracite Coal		$\begin{Bmatrix}1.400\\1.800\end{Bmatrix}$	1.0300	$\begin{Bmatrix}1.442\\1.852\end{Bmatrix}$	$\begin{Bmatrix}1.355\\1.796\end{Bmatrix}$
Bituminous Coal		$\begin{Bmatrix}1.200\\1.500\end{Bmatrix}$	1.0600	$\begin{Bmatrix}1.272\\1.590\end{Bmatrix}$	$\begin{Bmatrix}1.173\\1.514\end{Bmatrix}$
Fresh Water	H_2O	1.000	1.1101	1.110	1.000
Salt Water	200,000 ppm	1.146	1.0797	1.237	1.135
Oil	$n(CH_2)$	0.850	1.1407	0.970	0.850
Methane	CH_4	ρ_{meth}	1.2470	1.247 ρ_{meth}	1.335 ρ_{meth} − 0.188
Gas	$C_{1.1}H_{4.2}$	ρ_g	1.238	1.238 ρ_g	1.325 ρ_g − 0.188

Element	Photoelectric Cross Section	Atomic Number Z_e
Hydrogen	0.00025	1
Carbon	0.15898	6
Oxygen	0.44784	8
Sodium	1.4093	11
Magnesium	1.9277	12
Aluminum	2.5715	13
Silicon	3.3579	14
Sulfur	5.4304	16
Chlorine	6.7549	17
Potassium	10.0810	19
Calcium	12.1260	20
Titanium	17.0620	22
Iron	31.1860	26
Copper	46.2000	29
Strontium	122.2400	38
Zirconium	147.0300	40
Barium	493.7200	56

For a molecule made up of several atoms, a photoelectric absorption cross section index, P_e, may be determined based upon atomic fractions. Thus,

$$P_e = \frac{\Sigma A_i Z_i P_i}{\Sigma A_i Z_i}, \qquad \text{(Eq. 5-10)}$$

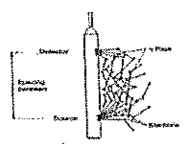
where A_i is the number of each atom in the molecule.

Name	Formula	Molecular Weight	P_e	ρ_e	ρ_a	U
Minerals						
Anhydrite	$CaSO_4$	136.146	5.055	2.960	2.957	14.95
Barite	$BaSO_4$	233.386	266.800	4.500	4.011	1070.00
Calcite	$CaCO_3$	100.090	5.084	2.710	2.708	13.77
Carnallite	$KCl{\cdot}MgCl_2{\cdot}6H_2O$	277.880	4.089	1.610	1.645	6.73
Celestite	$SrSO_4$	183.696	55.130	3.960	3.720	204.00
Corundum	Al_2O_3	101.960	1.552	3.970	3.894	6.04
Dolomite	$CaCO_3MgCO_3$	184.420	3.142	2.870	2.864	9.00
Gypsum	$CaSO_4{\cdot}2H_2O$	172.180	3.420	2.330	2.372	8.11
Halite	NaCl	58.450	4.650	2.165	2.074	9.65
Hematite	Fe_2O_3	159.700	21.480	5.210	4.987	107.00
Ilmenite	$FeO{\cdot}TiO_2$	151.750	16.630	4.700	4.460	74.20
Magnesite	$MgCO_3$	84.330	0.829	3.037	3.025	2.51
Magnetite	Fe_3O_4	231.550	22.080	5.180	4.922	109.00
Marcasite	FeS_2	119.980	16.970	4.870	4.708	79.90
Pyrite	FeS_2	119.980	16.970	5.000	4.834	82.00
Quartz	SiO_2	60.090	1.806	2.654	2.650	4.79
Rutile	TiO_2	79.900	10.080	4.260	4.052	40.80
Sylvite	KCl	74.557	8.510	1.984	1.916	16.30
Zircon	$ZrSiO_4$	183.310	69.100	4.560	4.279	296.00
Liquids						
Water	H_2O	18.016	0.358	1.000	1.110	0.40
Salt Water	(120,000 ppm)		0.807	1.086	1.185	0.96
	[illegible]		0.119	0.850	0.948	0.11

The density log (γ-γ) Density-Log

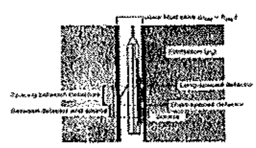
The tool measures the attenuation of incident gamma radiation, which is dependent on the electron density of the medium (Fig. 8.20).

A simple relationship gives the formation density, which is in turn related to the porosity. The curve is represented on a density scale (Fig. 8.21).



Principle of the gamma-gamma sonde

$$\phi = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f}$$

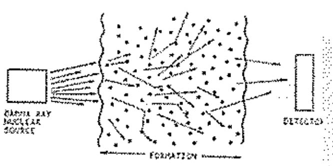


Principle of compensated logging tool

Fig. 8.20

THE LITHO-DENSITY TOOL

1. PRINCIPLE



• ELECTRONS OF THE FORMATION

(i) NUCLEAR SOURCE EMITS CONTINUOUSLY MEDIUM ENERGY GAMMA RAYS.

(ii) THESE GAMMA RAYS COLLIDE WITH THE ELECTRONS OF THE FORMATION, LOSE SOME OF THEIR ENERGY AT EACH COLLISION, AND ARE SCATTERED IN THE FORMATION.

(COMPTON SCATTERING)

(iii) THE TOOL COUNTS THE GAMMA RAYS WHICH REACH THE DETECTOR WITH A SUFFICIENT ENERGY LEVEL.

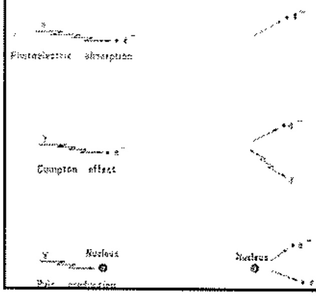
THE MORE ELECTRONS IN THE FORMATION, THE MORE COLLISIONS, THE MORE SCATTERING AND LOSS OF ENERGY OF THE GAMMA RAYS, ...

THE LITHO-DENSITY TOOL

MEASUREMENT PRINCIPLE

ELECTRON-GAMMA RAY INTERACTION

- COMPTON SCATTERING
- PHOTOELECTRIC ABSORPTION
- PAIR PRODUCTION



Density Logging Overview

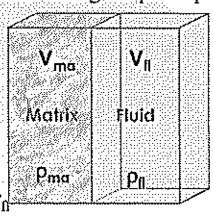
- Designed to measure electron density and gamma ray absorption properties of formation
- Principle: gamma rays continuously emitted from source, and lose energy as they collide with electrons present in formation
- Measurements:
  - bulk density (r_b)
  - photoelectric factor (P_e)
- Primary objectives:
  - porosity determination
  - lithology determination

Density Logging Applications

- Porosity (F) determination (*total* porosity)
- Lithology determination
- Provide a shale indication
- Estimate volume of shale (V_{sh}) when combined with other porosity measurements
- Provide a gas indication when combined with other porosity measurements
- Estimate gas saturation when combined with other porosity measurements

Porosity Determination

- Bulk density (r_b) is a function of…
  1. density of the rock "matrix"
  2. amount of porosity present
  3. density of the fluids filling the pore space
- Mathematically…
- $r_b = V_{ma}r_{ma} + V_{fl}r_{fl}$
- $r_b = (1 - F)r_{ma} + Fr_{fl}$



Porosity determination

- $\rho_b = (1 - \Phi)\rho_{ma} + \Phi\rho_{fl}$

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}$$

ρ_b = bulk density (measured by tool)

ρ_{ma} = matrix density (assumed)

ρ_{fl} = fluid density (assumed)

Provides an estimate of *total* porosity

Matrix density (ρ_{ma}) parameter

- Density of the actual rock matrix of formation
- Parameter determined by log analyst, petrophysicist. Can be derived from core lab measurements.
- Commonly assumed matrix densities (r_{ma})
  - Sandstone: 2.65 gm/cc
  - Limestone: 2.71 gm/cc
  - Dolomite: 2.87 gm/cc
- Represent pure lithologies at zero-porosity

Fluid density (ρ_{fl}) parameter

- Density of the fluid occupying the pore space
- Parameter determined by log analyst, petrophysicist.
- Represents the fluid present within pores of the volume of investigation (i.e., *flushed* zone)
- Commonly assumed fluid densities (r_{fl})
  - Fresh water-based: 1.0 gm/cc
  - Salt water-based: 1.1 gm/cc
  - Oil-based: 0.85 gm/cc
  - Air-drilled borehole any ideas??

Lithology determination

- The ability of a formation to absorb gamma rays is strongly related to average atomic number (Z) of elements present in the rock

$$P_e = \left(\frac{Z}{10}\right)^{3.6}$$

- Photoelectric factor (P_e) can be used to help estimate rock type, even in complex lithologies

Photoelectric factor (P_e)

- Compositionally pure formations have characteristic values of P_e

MATERIAL	P_e
Sandstone	1.81
Limestone	5.08
Dolomite	3.14
Shale(s)	2.5 – 3.5
Anhydrite	5.05
Halite	4.65
Coal	~ 0.2
Barite	266.82

Additional Density Logging Applications

- Estimation of hydrocarbon density
- Enhanced evaluation of shaly sandstone reservoirs
- Determination of overburden pressure
- Estimation of rock mechanical properties when used in combination with acoustic waveform data

Physics of the measurement

- Relates to energy loss experienced by gamma rays
- Gamma rays collide with electrons of atoms, causing them to be either scattered or absorbed
- Gamma rays returning to detectors exhibit a wide range of energy levels, depending upon type and number of collisions
- Scattering is proportional to electron density (r_e) of the formation
- Absorption depends upon the formation's average atomic number (Z)

Source of gamma rays

- The 1.5-Curie Cesium-137 chemical source emits a continuous stream of gamma rays

$$^{137}_{55}Cs \rightarrow {}^{137}_{56}Ba(unstable) + {}_{-1}\beta$$

$$^{137}_{56}Ba(unstable) \rightarrow {}^{137}_{56}Ba(stable) + \gamma(662keV)$$

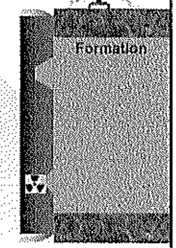
- Initial energy of these gamma rays is 662-keV

What is an "electron volt?"

- Unit of energy equal to the kinetic energy acquired by an electron passing through a potential difference of 1 volt
- A gamma ray with an energy level of 662-keV (kilo-electron volt) would have the same striking power as an electron accelerated through a 662,000 volt potential
- In other words, this is some pretty high energy!

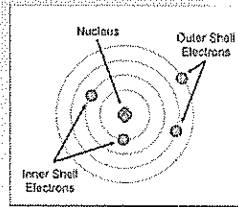
Energy loss in gamma rays

- Gamma rays traveling through formation collide with electrons
- In each collision, gamma loses some energy and is scattered along a different path of travel
- Ultimately (< 100-keV), gamma may lose enough energy to be absorbed
- Scattering and absorption results in a wide range of gamma energy levels at the tool's detectors



Energy loss in gamma rays

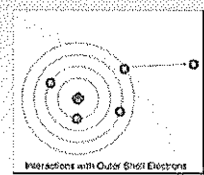
- Amount of energy lost depends upon whether collision is with inner shell or outer shell electron



- Binding energy (proportional to Z, decreases with distance from nucleus)

Energy loss in gamma rays

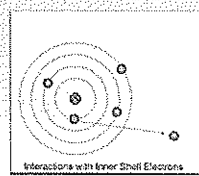
- At higher energy levels (> 100-keV), gamma rays interact with outer shell electrons
- If $E_g > E_{bind}$, electron takes on some of energy and is ejected



- Lithology-independent (weak relationship to Z)

Energy loss in gamma rays

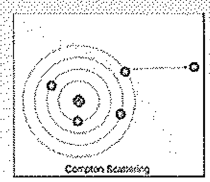
- At lower energy levels (< 100-keV), gamma rays interact with inner shell electrons
- If $E_g \approx E_{bind}$, all of energy is transferred to electron, and electron is ejected while gamma ray is absorbed



- Lithology-dependent (strong relationship to Z)

Compton scattering

- The most important lithology-independent mechanism of energy loss in gamma rays
- Requires higher energy levels (> 100-keV)



- Numerous Compton events can result in much lower energy levels (and, ultimately, even absorption)

Compton scattering

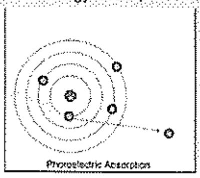
- The probability that a Compton event will occur is proportional only to formation's electron density (r_e)
- Electron density: number of electrons per cm^3
- More electrons → greater probability → higher r_e
- Bulk density (r_b) is related to electron density (r_e)...
  - $r_b = 1.0704 r_e - 0.1883$
- Conclusion: gamma rays > 100-keV are important in the determination of bulk density (r_b)

The "industry standard" equation

- All density tools actually "measure" electron density
- Bulk density is derived from the following relationship
  - $r_b = 1.0704r_e - 0.1883$
- Service companies may have different tools, but they all use this form of the equation
- The truth of the matter…
  We measure the number and energy levels of gamma rays from which we derive the electron density; then, we calculate bulk density

Photoelectric absorption

- The most important lithology-dependent mechanism of energy loss in gamma rays
- Requires much lower energy levels (< 100-keV)



- Absorbed gammas obviously can't be detected (but other very low energy level gammas are)

Photoelectric absorption

- The probability that photoelectric absorption will occur is proportional to atomic number (Z) of atom

$$P_e = \left(\frac{Z}{10}\right)^{3.6}$$

$$P_e \propto \frac{\text{Compton range gammas}}{\text{absorption range gammas}}$$

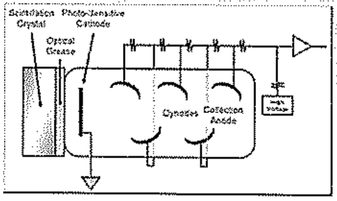
- Conclusion: gamma rays < 100-keV are important in the determination of photoelectric factor (P_e)

Gamma ray interactions with matter

- Compton scattering
- Photoelectric absorption
- Pair production
  (electron/positron emission)

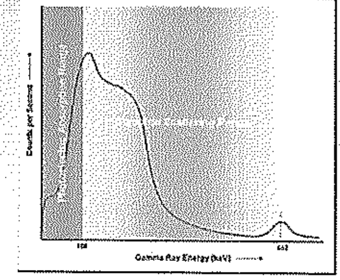
Scintillation detection

- Sodium iodide (NaI) scintillation crystals
- Two detectors: short-spaced and long-spaced



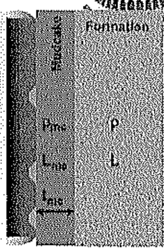
Scintillation detection

- Each detector measures the count rate and energy level of gamma rays reaching the tool



Deciphering what a count rate means

- Ideally, count rates should only provide information about density and lithology of formation
- Actually a function of several things:
  - r formation density
  - L formation lithology
  - r_{mc} mudcake density
  - L_{mc} mudcake lithology
  - t_{mc} mudcake thickness
- Count rates change as a function of variations in these physical properties

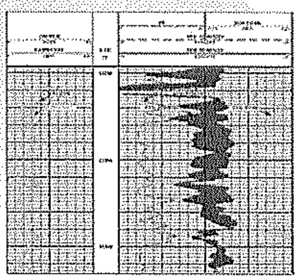


The count rate equation

- $\ln(C) = a_1 + a_2r + a_3r^2 + a_4r^3 + a_5L + a_6x_3 + a_7x_4$
- Each count rate is simultaneously solved for:
  - Electron density of formation (r…remember r_e?)
  - Lithology factor of formation (L)
  - x_3 – a factor related to the contrast between the density of the mudcake and density of the formation
  - x_4 – a factor related to the contrast between the lithology of the mudcake and lithology of the formation

Computing the results

- With values of r, L, x_3, and x_4 solved from the count rate equations, both the bulk density (r_b) and photoelectric factor (P_e) of the formation can be computed



Computing bulk density (ρ_b)

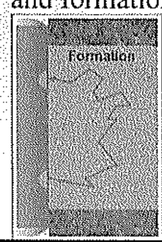
- Count rate equations were modeled for an 8-inch borehole filled with fresh water
- Electron density (r) derived from equations must be corrected for borehole diameters and mud weights different from the modeled conditions
- A minor correction is added
- IMPORTANT: This is known as the radius of curvature correction, and is NOT the same as the correction curves that appear on the log!
- What is meant by "radius of curvature"?

Computing bulk density (ρ_b)

- Once radius of curvature correction has been applied, bulk density (r_b) can be computed…
  - $r_b = 1.0704r_e - 0.1883$
- This equation is standard for all density tools
- But is this computed value of bulk density "correct"?
- What else is influencing the measurement that has yet to be accounted for?

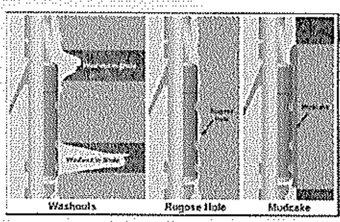
The problem of "stand-off"

- Measurements could be acquired with a single scintillation detector
- However, this would require direct contact between the detector and formation



The problem of "stand-off"

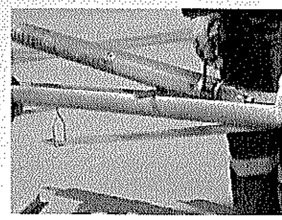
- Detectors may not be in direct contact with formation



- Count rates dependent upon scattering and absorption properties of formation and material that is creating the stand-off

The problem of stand-off

- Using two detectors helps minimize stand-off effects
- Short-spaced detector is more susceptible



- Tool design does not eliminate stand-off effects!

Spine and Ribs

- The zero mud cake line is referred to as the spine. The arc describing the locus of the mudcake affected points is called the ribs. The correct density for a point on a rib is where the rib connects to the spine

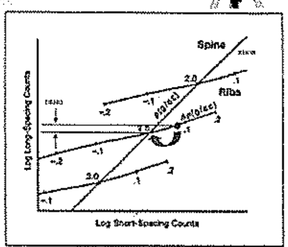


Figure 17.9. Spine-and-ribs chart.

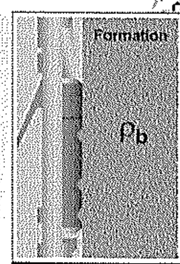
Density correction for stand-off

Ideal condition

- Direct contact
- No stand-off

Both detectors provide for an

- accurate measurement of
- bulk density (r_b)

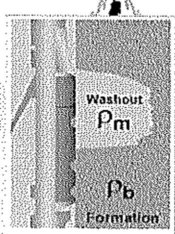


No correction is required

How many times do you think this happens??

Density correction for stand-off

- Washouts
- Stand-off exists
- Because $r_m < r_b$ in most cases,
- computed bulk density (r_b) will
- be less than true density

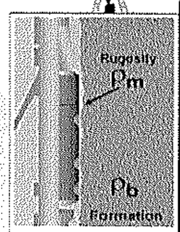


$\rho_m < \rho_b$

- A positive correction is required
- Magnitude of correction depends upon the stand-off distance and mud density

Density correction for stand-off

- Rugose borehole
- Stand-off exists
- Because $r_m < r_b$ in most cases,
- computed bulk density (r_b) will
- be less than true density

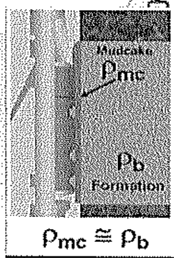


$\rho_m < \rho_b$

- A positive correction is required
- Magnitude of correction (much smaller than for wash-outs) depends upon the stand-off distance and mud density

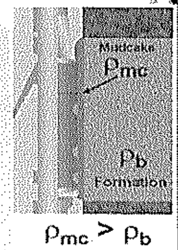
Density correction for stand-off

- Mudcake
- Stand-off exists
- In most cases $r_{mc} \approx r_b$; therefore,
- little—if any—correction required
- However, as mudcake thickness
- and mudcake density increase,
- the correction becomes more
- severe
- Correction may either be positive or negative



Density correction for stand-off

- Mudcake in heavy muds
- Stand-off exists
- Barite- or hematite-loaded
- Because $r_{mc} > r_b$, the computed
- bulk density (r_b) will be greater
- than true density
- A negative correction is required



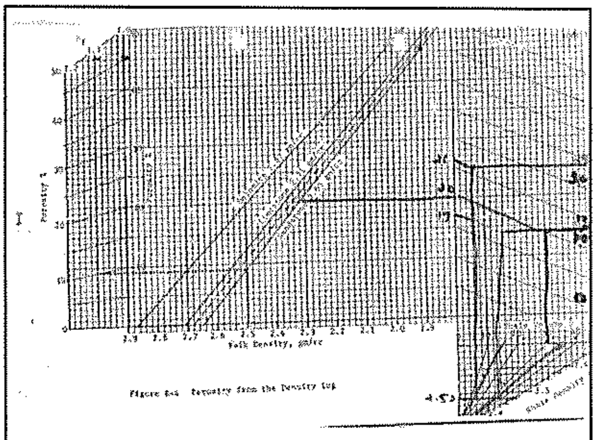
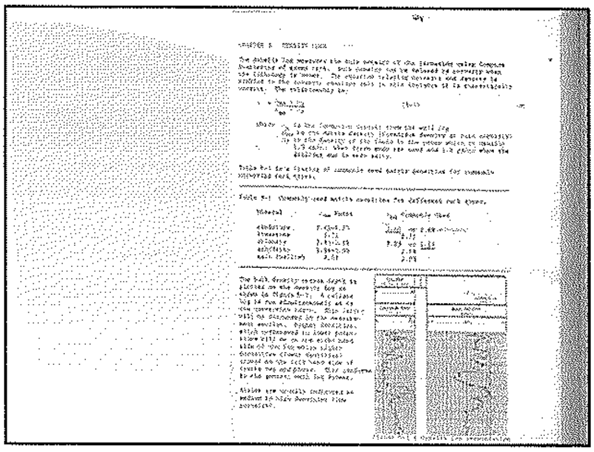


Figure 8-4 Porosity from the Density Log



Example 8-1 Use of Figure 8-4 for determination of porosity from density

Given: formation is a sandstone, density is 2.5 gm/cc

the porosity for a fluid density of 1.0 gm/cc is 9%
if the fluid density is 1.1 (salty mud) - porosity is 10%

Extra: if the formation was a limestone and the mud fresh the porosity would be 12.2% or in realistic terms 12%

The shale correction part of Figure 8-4 will be explained in chapter 13 on shaly sandstone interpretation.

If the formation has little or no invasion the light density of the formation hydrocarbon can influence the density measured. The effect of oil is not too significant as the density of oil is around 0.8 and this is partially offset by the formation water being over 1.0 gm/cc. Gas significantly effects the density of a formation. If a fluid density of 1 is assumed, the porosity calculated will be too high in a noninvaded gas sandstone. In a noninvaded sandstone the fluid density will be:

$$\rho_f = S_w \rho_w + (1 - S_w) \rho_h \qquad (8\text{-}2)$$

where the subscript w refers to the formation water and h to hydrocarbon. To find the fluid density it is necessary to know the hydrocarbon density, the formation water density and the water saturation. The latter is of course what we are trying to find. An approximate gas density can be obtained from Figure 8-5. This correlation assumes a Gulf Coast average temperature gradient and an average pressure gradient. If you do not know the gas specific gravity use 0.7. If you wish to use this chart in Alberta add about 2000 feet to the depth before entering the graph. The formation water

Density Logs

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad \text{— (8.1)}$$

Non Invaded S.S.

$$\rho_f = S_w \rho_w + (1 - S_w)\rho_h \quad \text{— (8.2)}$$

$$F_r = 0.91\,\phi^{-2} \quad (2.7) \qquad S_w = \sqrt{\frac{F_r R_w}{R_t}} \quad \text{— (1-10)}$$

$$S_w = \sqrt{\frac{F_r R_w}{R_t}}$$

$$= \sqrt{0.91\,\phi^{-2} \cdot \frac{R_w}{R_t}}$$

$$\rho_f = S_w \rho_w + (1 - S_w)\rho_h \quad \text{— (8.2)}$$

$$= \left(\sqrt{0.91\,\phi^{-2} \cdot \frac{R_w}{R_t}}\right)\rho_w + \left(1 - \sqrt{0.91\,\phi^{-2}\frac{R_w}{R_t}}\right)\rho_h$$

in eqn (1)

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \frac{0.9}{\phi}\sqrt{\frac{R_w}{R_t}}(\rho_w - \rho_h) - \rho_h}$$

$$\phi(\rho_{ma} - \rho_h) - 0.9\sqrt{\frac{R_w}{R_t}}(\rho_w - \rho_h) = \rho_{ma} - \rho_b \quad \text{— 8.3}$$

$$\phi = \left(0.9\sqrt{\frac{R_w}{R_t}}(\rho_w - \rho_h) + \rho_{ma} - \rho_b\right) / (\rho_{ma} - \rho_h)$$

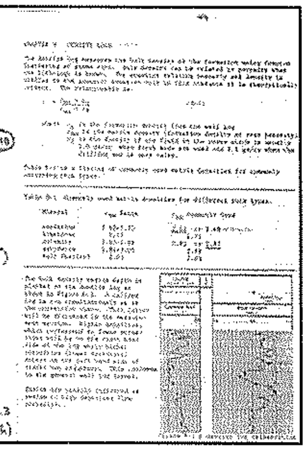
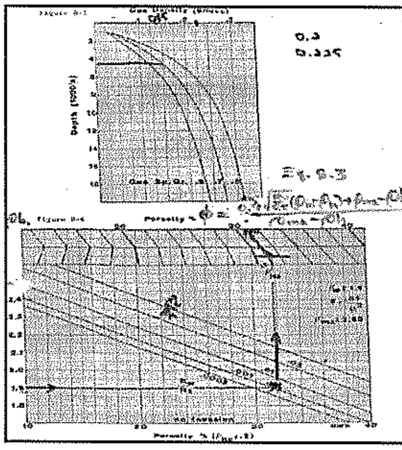
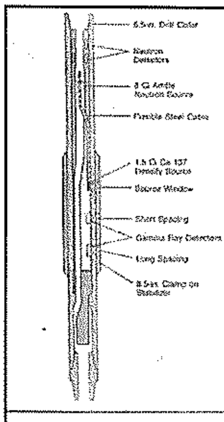


Table 8-3 Density/salinity relationships for aqueous NaCl

Salinity (ppm NaCl)	Density (gm/cc)
0	1.0
20,000	1.01
50,000	1.03
100,000	1.07
150,000	1.11
200,000	1.15
[illegible],000	1.19

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$





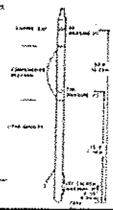
5-27—Schematic of the CDN tool.

(1) THE LITHO-DENSITY TOOL MEASURES DIRECTLY THE BULK DENSITY OF THE FORMATION BY DETERMINING THE SLOWING DOWN EFFECT OF FORMATION ELECTRONS ON THE GAMMA RAYS EMITTED BY A NUCLEAR SOURCE. IT ALSO MEASURES THE PHOTOELECTRIC EFFECT OF THE FORMATION WHICH IS USEFUL FOR LITHOLOGY IDENTIFICATION. HOWEVER, THE Pe CURVE IS AFFECTED BY BARITE IN THE MUD.

(2) CORRECT MEASUREMENT OF FORMATION DENSITY REQUIRES GOOD APPLICATION OF THE TOOL AGAINST THE BOREHOLE WALL. [illegible] READINGS MAY BE ERRONEOUS IN CASE OF A WASHED OUT HOLE.

(3) THE LDT CAN BE RUN IN COMBINATION WITH THE CNL AND THE GAMMA RAY.

(4) IT CANNOT BE RUN THROUGH CASING.



TOOL SPECIFICATIONS

Tool Length	= 31 ft or 9.5 m
Diameter	= 4" or 10cm
Maximum Hole Size	= 22" or 56cm
Maximum Temperature	= 350°F or 175°C
Maximum Pressure	= 20,000 psi or 1,400 bar
Total Weight	= 247 lbs or 112 kg

RECOMMENDED RECORDING SPEED 1,800 ft/hr

Equations 8-1 and 8-2 can be solved by trial and error when combined with equation 2-10. If equations 2-7, 2-10, 8-1 and 8-2 are combined

$$\phi = \frac{.9\sqrt{\frac{Rw}{Rt}}(\rho_w - \rho_h) + \rho_{ma} - \rho_b}{\rho_{ma} - \rho_h} \quad (8-3)$$

$F_r = \frac{0.81}{\phi^2}$

An approximate solution for this equation can be obtained using Figure 8-6. Figure 8-6 is accurate for low values of Rw/Rt. Figure 8-6 and equation 8-3 assume that there is no invasion. The solution is not very sensitive to modest variations in Sw. Example 8-2 shows an example of a formation with almost no invasion and illustrates the use of Figure 8-6.

Example 8-2 Interpretation of an induction electric log and density log in a gas zone with no invasion.

See log examples 8-2a and 8-2b

Interval	induction electric log	4639 – 4665
	density log	4633 – 4659
	(notice that the density and induction log are off depth)	

Data: density = 1.9 gm/cc from log
Rt = .20 ohm m from induction log
Rw = .028 from adjacent formation (@ 140°F)
this gives water salinity of 170,000 ppm (Fig. 2-2)
water density is thus 1.12
from Fig. 8-5 gas density is 0.15
Rw/Rt = .0014

porosity from Fig. 8-6 is 31% (slightly over)
porosity from equation 8-3 is 31.3%

water saturation is 10%

Density Log Formulas

$$\phi_D = \frac{\rho_{ma} - \rho_b - \Delta\rho_b}{\rho_{ma} - \rho_f}$$

if shaly

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh}\left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}\right)$$

invaded Zone Gas/water System

$$\rho_f = (1 - S_{xo})\rho_g + S_{xo}\rho_{mf}$$

if only density log run for ϕ need correction

$$\rho_{bc} = \rho_b - \Delta\rho_b$$

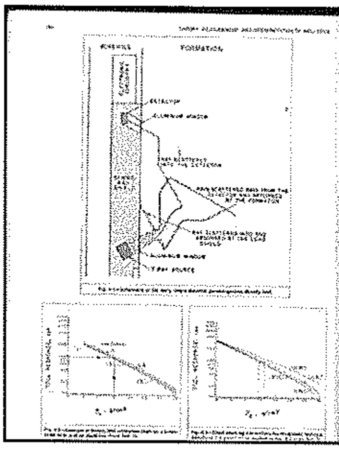
Oil Bearing formation

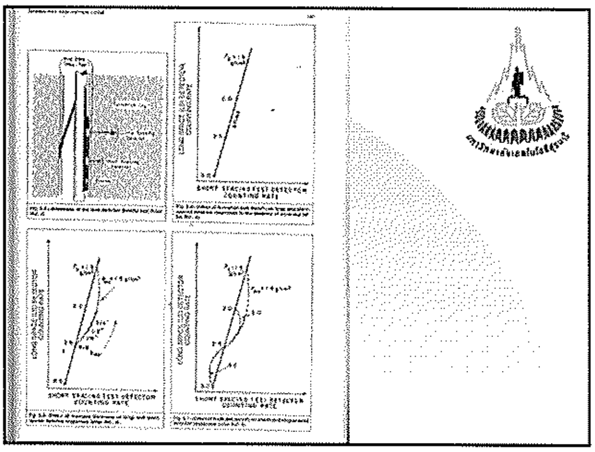
$$\Delta\rho_b = 1.07\phi S_{hr}[(1.11 - 0.15P)\rho_{mf} - 1.15\rho_h - 0.03]$$

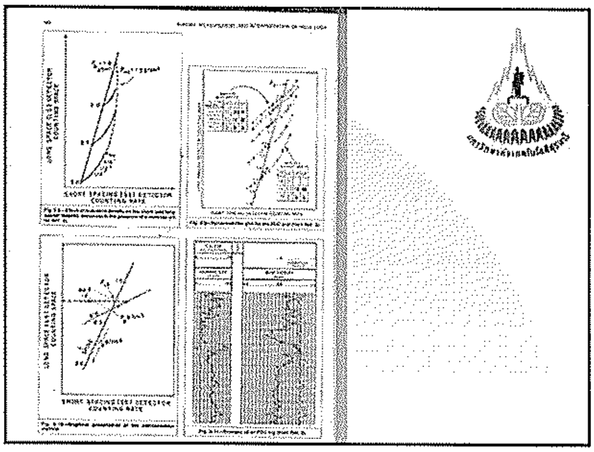
for Gas-bearing

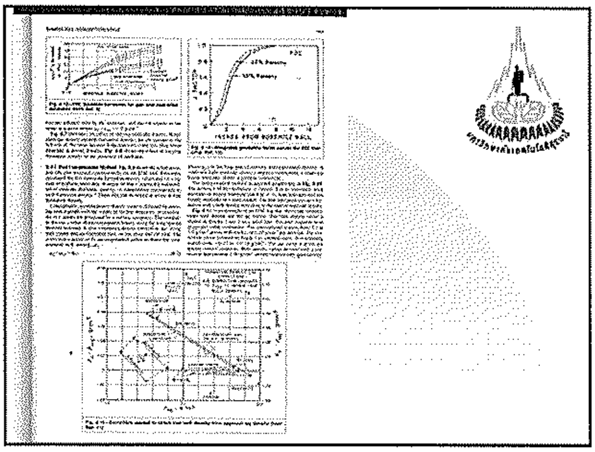
$$\Delta\rho_b = 1.07\phi S_{hr}[(1.11 - 0.15P)\rho_{mf} - 1.24\rho_h]$$

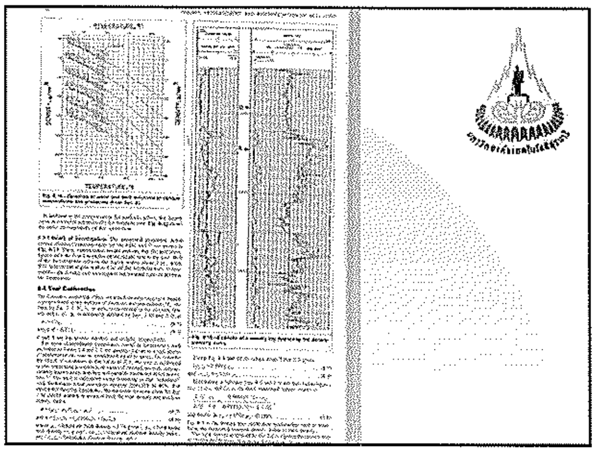
where P = ppm ras NaCl eq. conc

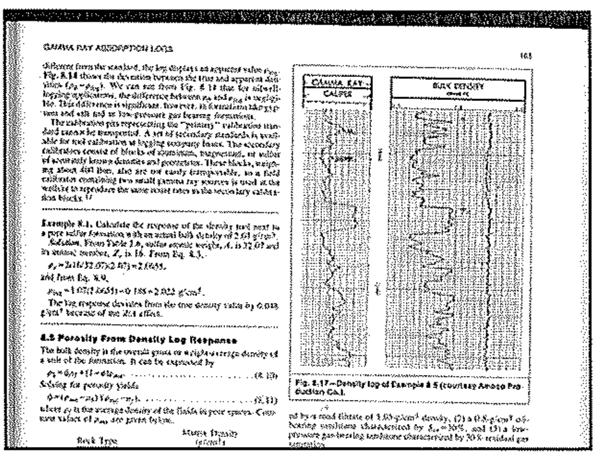


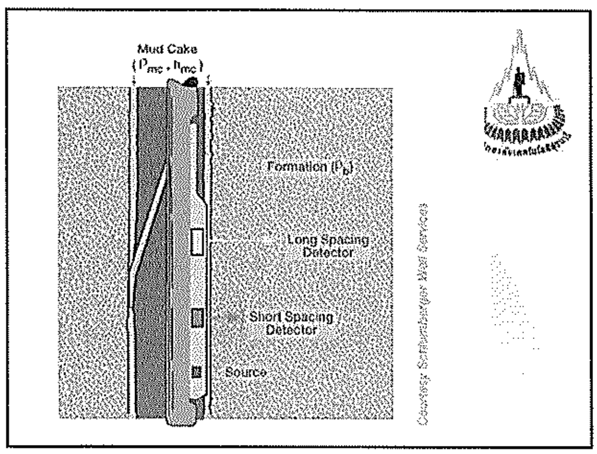









GAMMA RAY ABSORPTION LOGS
Example 8.1.
8.5 Porosity From Density Log Response
GAMMA RAY
CALIPER
BULK DENSITY
Fig. 8.17—Density log of Example 8.5 (courtesy Amoco Production Co.).


Mud Cake
(ρ_{mc}, h_{mc})
Formation (ρ_b)
Long Spacing Detector
Short Spacing Detector
Source
Courtesy Schlumberger Well Services

8.3 Porosity From Density Log Response

Fig. 8.17—Density log of Example 8.5 (courtesy Amoco Production Co.).

Example 8.3. A water-bearing sandstone displays a 2.1-g/cm³ bulk density. Calculate the density porosity using a matrix density of 2.68 g/cm³. Compare this value to that calculated with the normally assumed matrix density of 2.65 g/cm³.

Solution. From Example 8.2,

This represents a deviation of ~1.5 porosity units and a relative error of about ~4%.

---

filled sandstone parameters (see log heading). The log displays a negative apparent porosity of −6% next to Zone A. Fig. 8.11 indicates that a negative value results from the fact that the measured ρ_b is greater than the assumed ρ_{ma}. It follows that the true matrix density is greater than the true sandstone density. It is also greater than the density of limestone (ρ_b=2.75>2.71). Knowledge of lithology is required for accurate determination of the true porosity of this zone.

Although the porosity of Zone B is positive, it can still be an apparent porosity value because the lithology can be something other than sandstone. The logs indicate (1) that the borehole is regular and drilled to gauge (bit size is most certainly 7⅞ in.); (2) that gamma ray response is low; (3) that $\Delta\rho$ ≈0, indicating possible absence of mudcake, which, in turn, suggests a low-permeability formation; and (4) that lithologies other than sandstone are present—e.g., Zone A.

These facts indicate that Zone B is probably not sandstone. Its true porosity can be determined only after accurate lithologic identification.

Example 8.5. Fig. 8.17 shows the density tool's response obtained over a sand/shale series.

a. Calculate the average porosity of the clean sand interval.

b. Using a matrix density of 2.65 g/cm³, calculate the average density porosity of shales. How does the value compare to the true porosity? Explain the difference, if any.

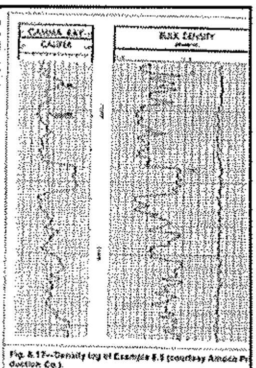


Fig. 8.17—Density log of Example 8.5 (courtesy Amoco Production Co.).

Solution.

a. The clean sand intervals identified by the lowest natural gamma ray display an average density of 2.16 g/cm³. Using matrix and fluid densities of 2.65 and 1 g/cm³, respectively, in Eq. 8.11 yields

ϕ_D=(2.65−2.16)/(2.65−1)=0.297 or 30%.

This value is representative of the true porosity.

b. The shale zone located in the interval of 12,339 to 12,359 ft displays an average bulk density of 2.46 g/cm³. Using 2.65 and 1 g/cm³ for the matrix and fluid densities gives

ϕ_D=(2.65−2.46)/(2.65−1)=0.115 or 12%.

This value is very small compared with shale's relatively high porosity. This difference is probably the result of tool calibration performed in limestone formations. This calculation indicates that the porosity curve, such as that of Fig. 8.16, displays an apparent porosity value in shales. The apparent density porosity in shales differs considerably from the true value.

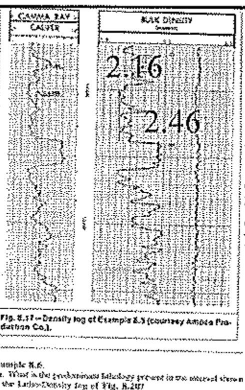


Fig. 8.17—Density log of Example 8.5 (courtesy Amoco Production Co.).

8.5 Litho-Density Tool

The Litho-Density Tool is a relatively new density measurement device. Because of changes in design and its ability to provide additional measurement, it is a considerable improvement over the compensated tool. In the newer design, the spacing of the detectors has been shortened. Thus, the counting rates have been increased and the statistical uncertainty of the measurements has decreased. This design also makes the density measurement less sensitive to the presence of mudcake, especially those containing high Z-value additives, such as barite.

Spectral analyses of the detected gamma ray make possible the measurement of the effective photoelectric absorption cross-section index for the formation, P_e. P_e, which has the unit of barns per electron, is defined as

A volumetric photoelectric absorption cross-section, U, that has the unit of barns per volume can be defined as

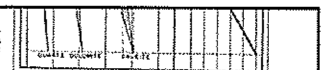


Fig. 8.19—Effect of porosity and fluid type on P_e (from Ref. 8).

Fig. 8.18 shows an example of a Litho-Density log. In addition to the bulk density curve (solid) and the correction curve (dotted), the P_e curve (dashed) is presented on Tracks 2 and 3 on a scale of 1 to 11 barns/electron.

The P_e value is also used in combination with the density value to analyze two-mineral matrices and to determine porosity. It is combined with density and neutron porosity to analyze more complex lithologies. These uses are discussed in Chap. 14.

Example 8.6.

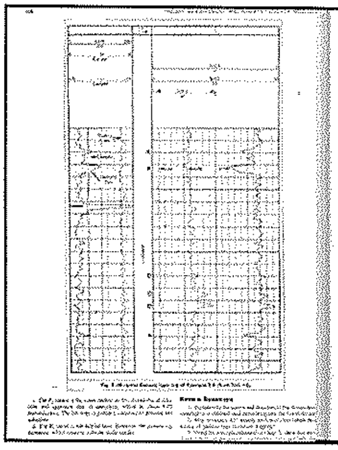
a. What is the predominant lithology present in the interval shown by the Litho-Density log of Fig. 8.20?

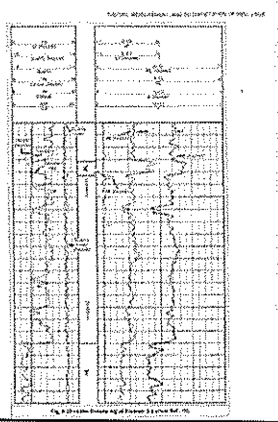
b. What is the range of porosity of this predominant lithology?

c. Describe the lithology of the thin zones marked by O's.

d. Describe the lithology of the thin zones marked by N's.

Solution.





Appendix B
Answers to Selected Problems

can be expressed by Eq. 8.1. Find an expression for the coefficients α and β.

4. The random occurrence of radioactive events introduces a degree of uncertainty into the measurement. Explain why, in density logging, the degree of uncertainty increases as porosity decreases.

5. Why is the dual-detector density tool superior to the single-detector density tool?

6. What is the use of the spine-and-ribs plot? How was it generated?

7. Discuss the Z/A effect.

8. What conditions should prevail for the tool to yield a true bulk density reading?

9. What conditions should prevail for Eq. 8.11 to yield a true porosity value?

10. Why is the density shale porosity considerably different from the true porosity?

11. Why is the Litho-Density Tool better than its predecessor, the FDC tool?

12. What is the parameter P_e? What formation property does it measure?

13. Why is the P_e curve affected only slightly by the formation porosity and fluid type?

Problems

8.1 The compensated density log of Fig. 8.21 was recorded in a 9⅞-in. borehole drilled with freshwater-based mud in a sand/shale series.

a. Select zones representative of the sections that show borehole enlargement and of the regular borehole sections.

b. Read and tabulate the caliper, bulk density, and $\Delta\rho$ values for each of these zones.

c. Plot $\Delta\rho$ vs. caliper reading. Does a correlation between these two parameters emerge? Explain why or why not.

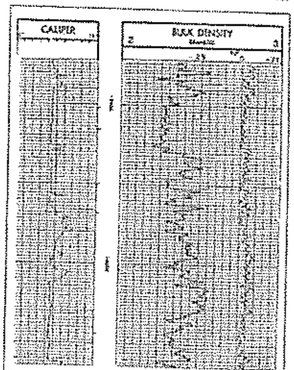


Fig. 8.21—Compensated density log of Problem 8.1 (courtesy Amoco Production Co.).

8.2 Calculate the response of the density tool next to pure aluminum and magnesium blocks of 2.713- and 1.777-g/cm³ bulk density, respectively.

8.3 A density tool calibrated in terms of freshwater-filled limestone generated a bulk density log. This log, in turn, was used to calculate a density porosity log using limestone matrix density and unit fluid density. Prepare a chart that can be used to convert the porosity values displayed by the log to true porosity values for sandstone, limestone, dolomite, and anhydrite formations.

8.4 Construct a chart that represents the transform between the electron density and the density tool bulk density. Show the limestone and water points on the transform.

8.5 Calculate the parameter C of Eq. 8.3 for shale made up entirely of kaolinite. The composition of kaolinite is $Al_4(Si_4O_{10})(OH)_8$.

8.6 Give your best estimate of the lithology and porosity of Zones X and Y in Fig. 8.22.

8.7 Fig. 8.23 shows two density logs run through sandstone Formation A in a gas injection well. Run 1 was made when the formation was fully saturated with water of 50,000 ppm salinity before gas injection. Run 2 was made several months after gas injection started. Estimate the gas saturation in the vicinity of the wellbore. The injected gas is mostly methane. Formation temperature and pressure are 100°F and 2,000 psia, respectively.

8.8 Refer to the density log of Fig. 8.24 in answering the following questions.

a. How representative is the log response at the levels marked with X's? Explain.

b. If the clean sands of the interval illustrated by the log are known to display a more-or-less constant porosity, give your best estimate of that porosity value.

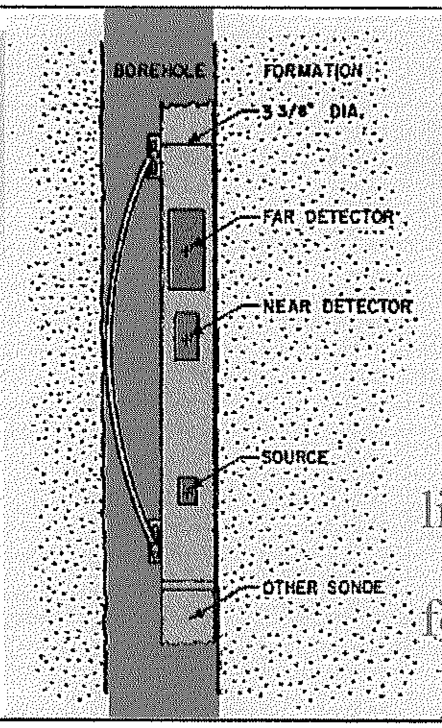
c. Calculate a density porosity at Level Y. Explain why this value is different from that calculated in Part b.

Nomenclature

A = atomic weight
h = thickness, ft
P_e = photoelectric absorption cross-section index, barns/electron
R = detector count rate, counts/sec
S = saturation, fraction
U = volumetric photoelectric cross section, barns/cm³
Z = atomic number
α,β = coefficients in Eq. 8.1
ρ = density, g/cm³
ϕ = porosity, fraction

Subscripts

a = apparent
b = bulk
D = density tool
e = electron
f = fluid
g = gas
h = hydrocarbon
log = logging tool response
ls = limestone
LS = long-spaced detector
ma = matrix
mc = mudcake
mf = mud filtrate
o = oil
or = residual oil
t = true
w = water
xo = flushed zone



CHAPTER9 Neutron Logs

porosity

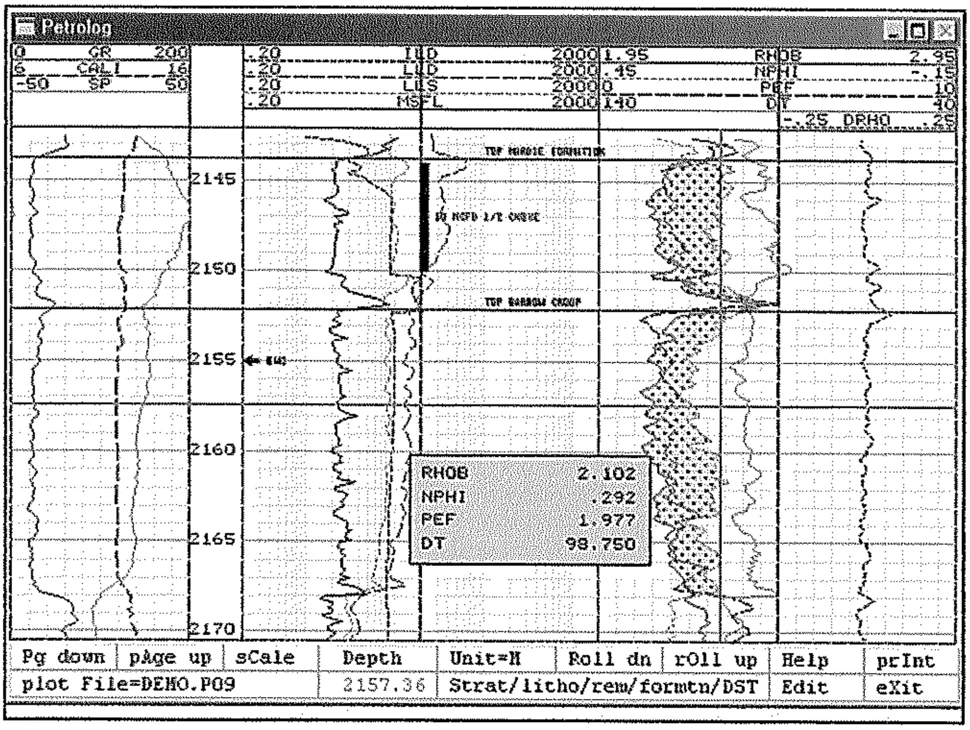
gas detection,

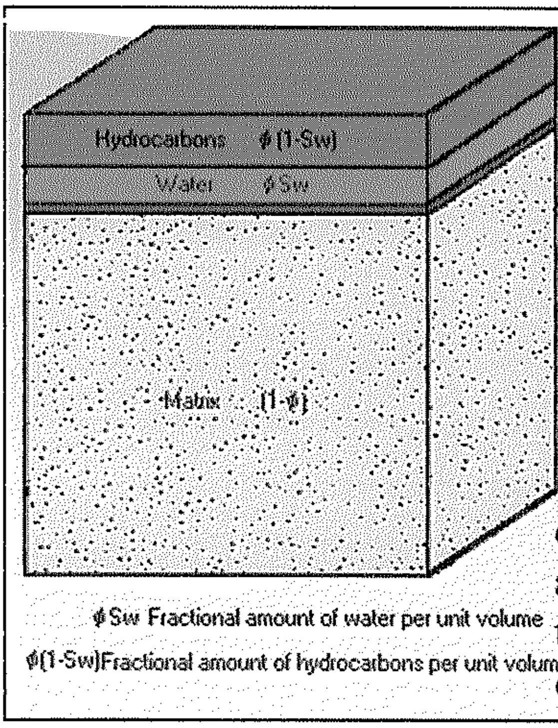
shale volume determination

lithology indication

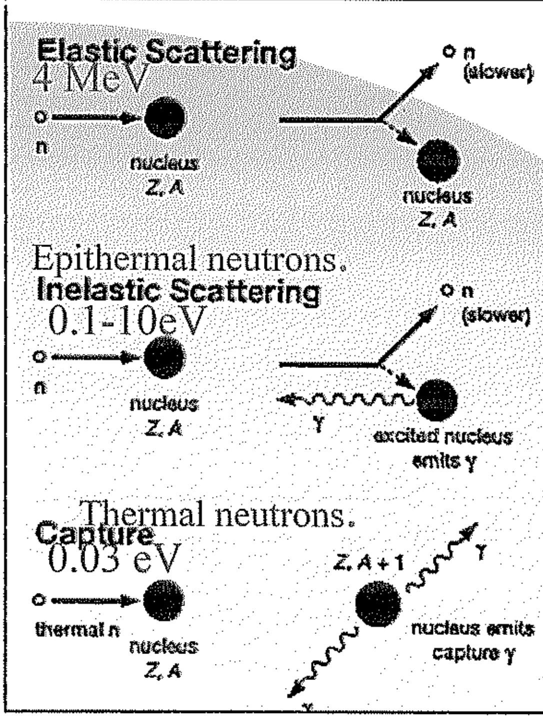
formation fluid type.

- Neutron Logging Applications
- Neutron tools are used primarily to determine:
- porosity, usually in combination with the density tool
- gas detection, usually in combination with the density tool, but also with a sonic too
- shale volume determination, in combination with the density tool
- lithology indication, again in combination with the density log and/or sonic log
- formation fluid type.
- Depending on the device, these applications may be made in either open or cased holes. Additionally, because neutrons are able to penetrate steel casing and ceme these logs can be used for depth tie-in as well as providing information on porosity and hydrocarbon saturations in cased holes. Figure 1: Generalized Neutron Loggin Tool illustrates a typical neutron logging tool.

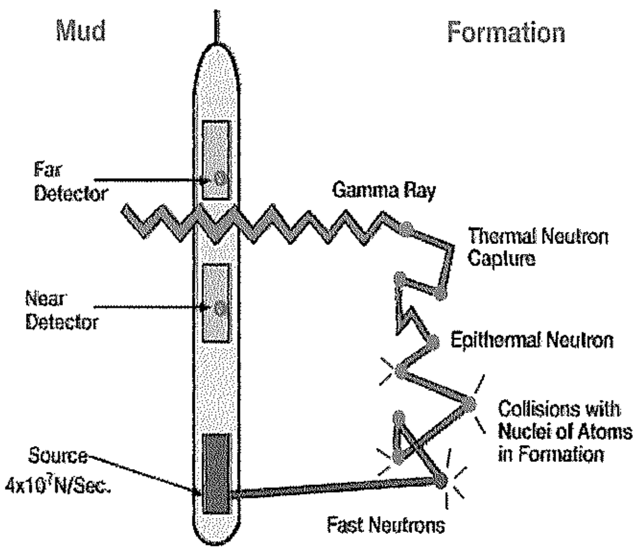




The Neutron tool is used to determine primary formation porosity, often called the pore space on the formation rock which is filled with water, oil or gas. Together with other tools like the density, the lithology and formation fluid type can also be determined.



An Am241Be source emits neutrons into the formation at approximately **4MeV.** (Plutonium Berilium sources are no longer used since they can be broken down to create atomic weapons). After collisions with the formation, the neutron energy levels fall to **between 0.1 and 10eV. These are known as epithermal neutrons.** After [illegible] collisions neutron energy levels fall **below 0.03eV and these are termed thermal neutrons.** By virtue of its similar mass to neutrons, Hydrogen more than any other element in the formation slows down the neutrons dramatically. A useful analogy is a billiard ball interacting with a bowling ball or a ping-pong ball. The billiard ball only loses significant velocity when it hits another billiard ball not when it hits a ping-pong ball or bowling ball. Since hydrogen is primarily only present in water, oil and gas, the neutron tool gives a direct measurement of the fluid in the pore space of clean formations. Two detectors, one short spaced and the other long spaced from the source are used to eliminate some borehole effects and detect the number of neutrons returning back to the tool. A low neutron return count indicates the presence of hydrogen and therefore porosity.



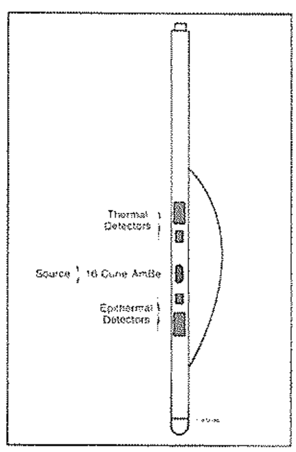
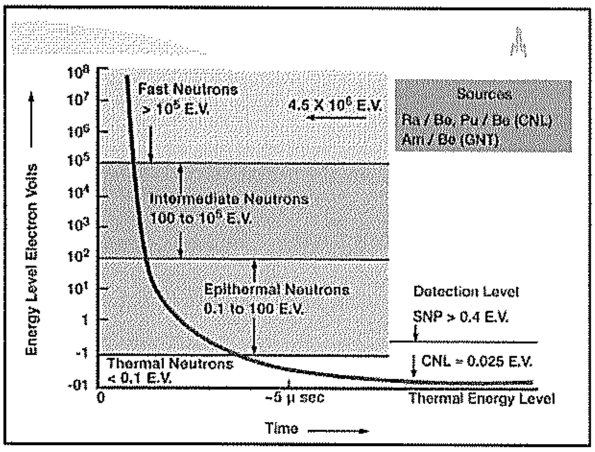
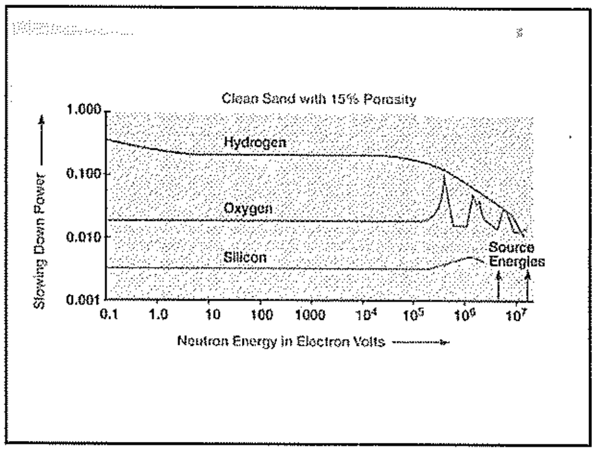
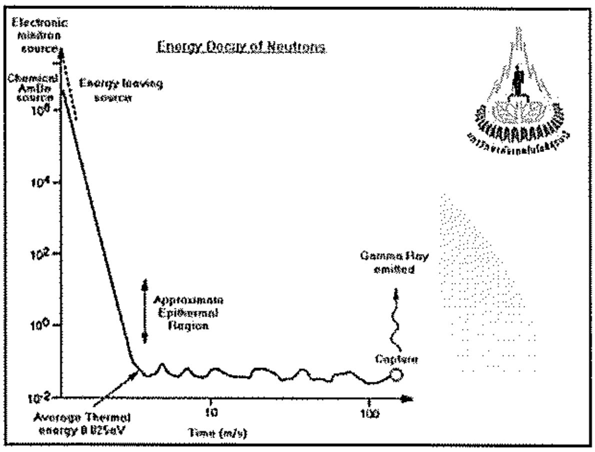
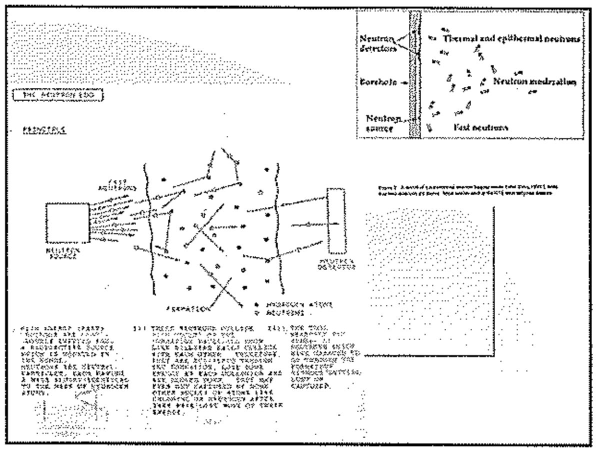


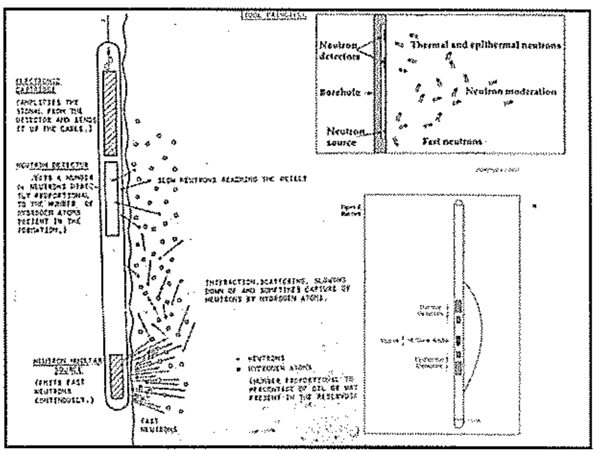
Fig. 5-20—CNT-G tool configuration.

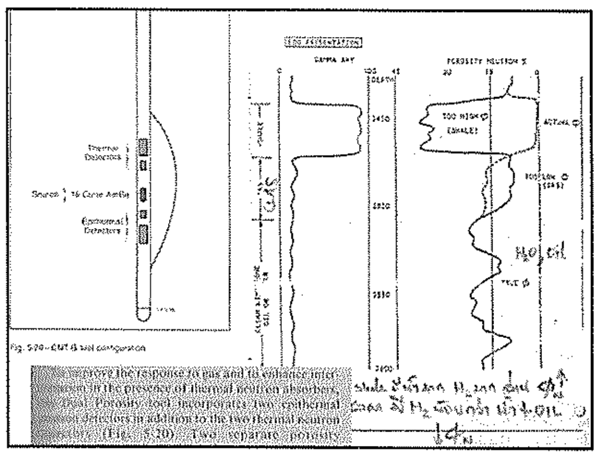

Fast Neutrons
> 10^5 E.V.
4.5 X 10^6 E.V.
Sources
Ra / Be, Pu / Be (CNL)
Am / Be (GNT)
Intermediate Neutrons
100 to 10^5 E.V.
Epithermal Neutrons
0.1 to 100 E.V.
Detection Level
SNP > 0.4 E.V.
CNL = 0.025 E.V.
Thermal Neutrons
< 0.1 E.V.
Energy Level Electron Volts
~5 μ sec
Thermal Energy Level
Time

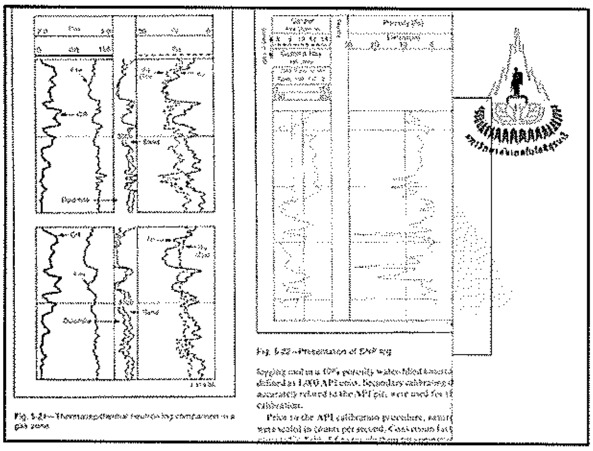

Clean Sand with 15% Porosity
Hydrogen
Oxygen
Silicon
Source
Energies
Slowing Down Power
Neutron Energy in Electron Volts


Energy Decay of Neutrons
Electronic neutron source
Chemical AmBe source
Energy leaving source
Approximate Epithermal Region
Gamma Ray emitted
Capture
Average Thermal energy 0.025eV
Time (m/s)


Neutron detectors
Thermal and epithermal neutrons
Borehole
Neutron moderation
Neutron source
Fast neutrons


Neutron detectors
Thermal and epithermal neutrons
Borehole
Neutron moderation
Neutron source
Fast neutrons


Thermal Detectors
Source
Epithermal Detectors
GAMMA RAY
POROSITY NEUTRON %
GAS
Fig. 5-20 – CNT-G tool configuration



SUMMARY NEUTRON TOOL (CNL)

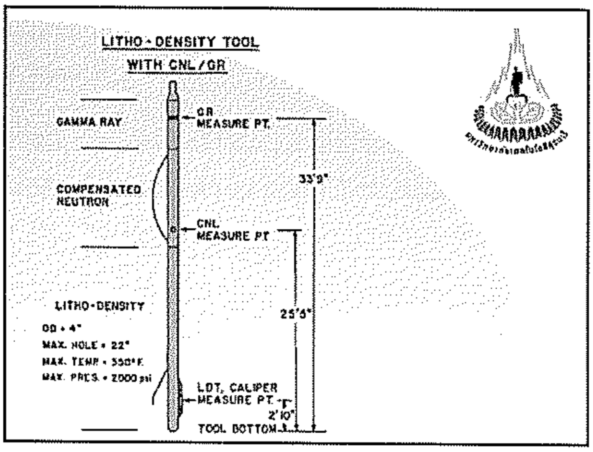
1) THE NEUTRON TOOL MEASURES HYDROGEN CONCENTRATION IN THE FORMATION INTERPRETED IN TERMS OF POROSITY.

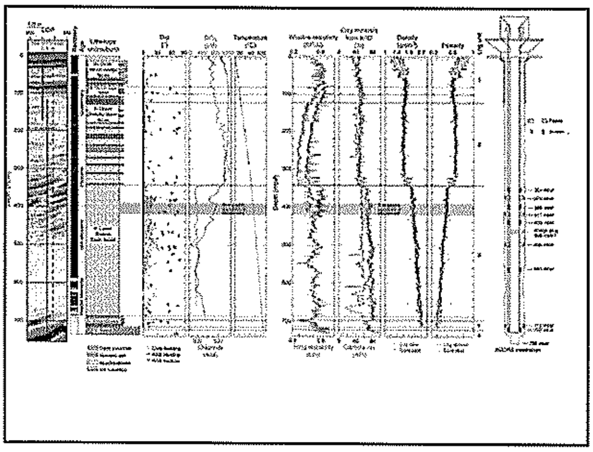
2) NEUTRON MEASURED POROSITY DIFFERS FROM EFFECTIVE POROSITY WHENEVER SHALE OR GAS IS PRESENT IN THE FORMATION. HOWEVER, ACCURATE POROSITIES CAN BE DETERMINED BY COMPARISON WITH OTHER NUCLEAR LOGS (LITHO DENSITY AND SONIC).

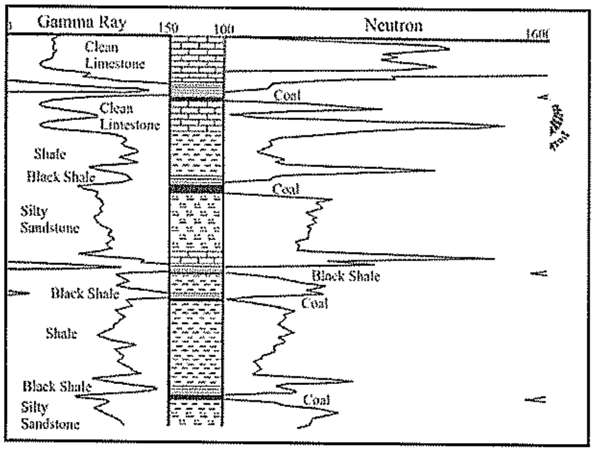
3) THE CNL NEUTRON TOOL CAN BE RUN IN COMBINATION WITH MOST OTHER LOGGING TOOLS USUAL COMBINATION IS WITH THE LDT/GR.

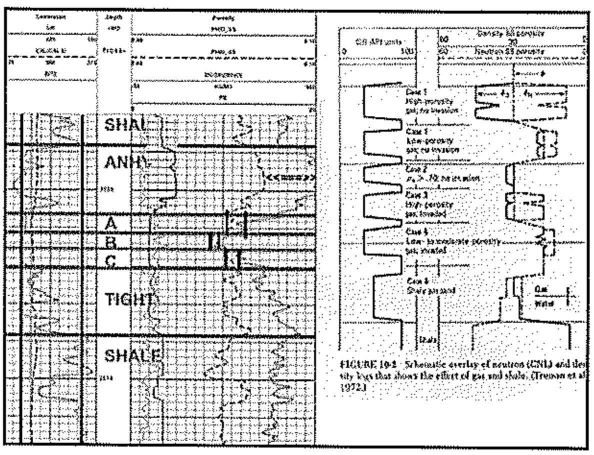
4) THE CNL CAN BE RUN THROUGH CASING.

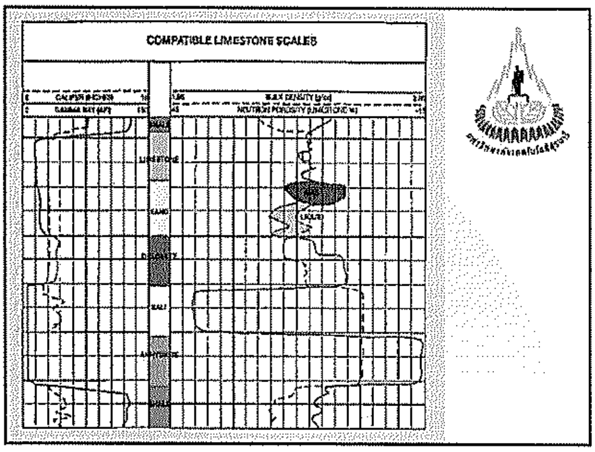
5) INFLUENCE OF THE BOREHOLE ON THE NEUTRON RESPONSE IS VERY MODERATE AND COMPENSATED FOR.

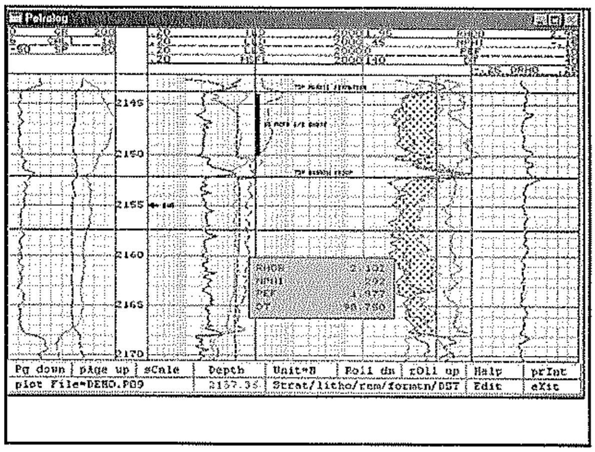


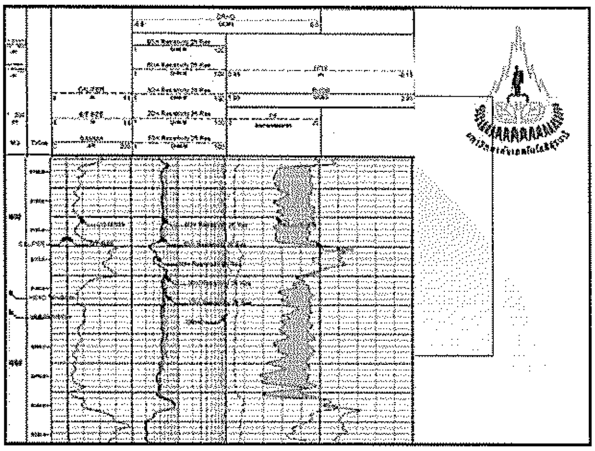


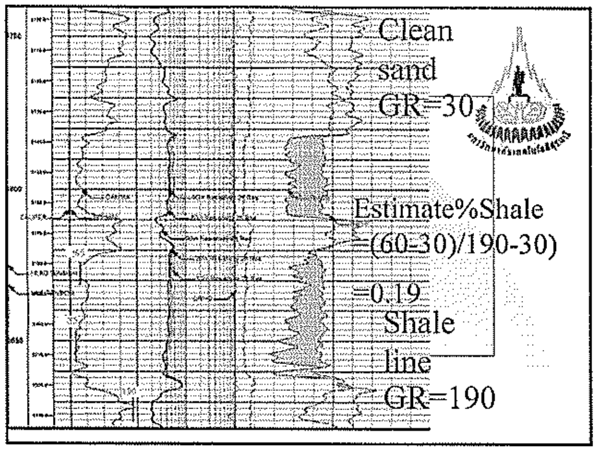


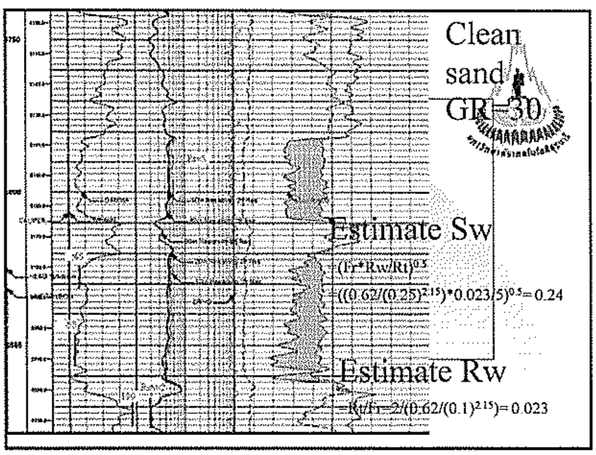












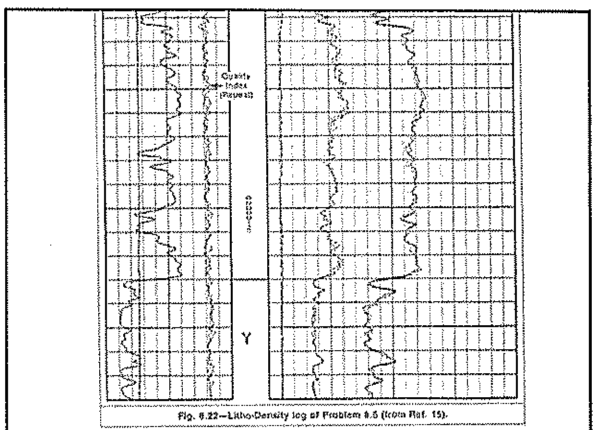


Fig. 9.22—Litho-Density log of Problem 9.5 (from Ref. 15).

GAMMA RAY ABSORPTION LOGS 171

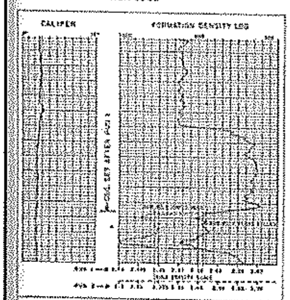
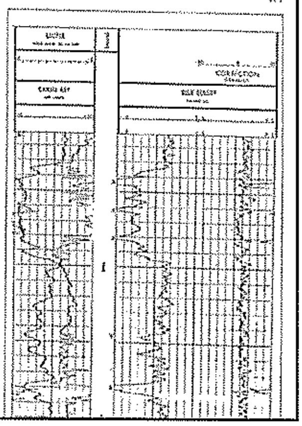


Fig. 8.23—Density log of Problem 8.7 (from Ref. 16).



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1. Nexon, G.R. et al.: "Subsurface Formation Density Logging," Geophysics (1954) 19, No. 3, 636.
2. Baker, P.E.: "Density Logging with Gamma Rays," Trans., AIME (1957) 210, 289-94.
3. Pickell, J.J. and Heacock, J.G.: "Density Logging," Geophysics (Aug. 1960) 25, No. 4, 891-904.
4. Wahl, J.S. et al.: "The Dual Spacing Formation Density Log," JPT

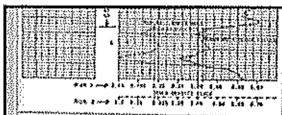

Fig. 8.23—Density log of Problem 8.7 (from Ref. 16).

References

1. Nexon, G.R. et al.: "Subsurface Formation Density Logging," Geophysics (1954) 19, No. 3, 636.
2. Baker, P.E.: "Density Logging with Gamma Rays," Trans., AIME (1957) 210, 289-94.
3. Pickell, J.J. and Heacock, J.G.: "Density Logging," Geophysics (Aug. 1960) 25, No. 4, 891-904.
4. Wahl, J.S. et al.: "The Dual Spacing Formation Density Log," JPT (Dec. 1964) 1411-16; Trans., AIME, 231.
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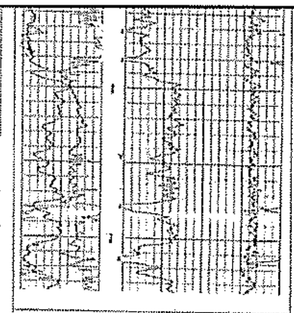

Fig. 8.24—Density log of Problem 8.8 (courtesy Amoco Production Co.).

14. Edmundson, H. and Raymer, L.L.: "Radioactive Logging Parameters for Common Minerals," Log Analyst (Sept.-Oct. 1979) XX, No. 5, 38-47.
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CHAPTER 7 PROBLEMS

1. On example 7-1 the caliper shows mudcake as hole diameter less than bit size (8") which indicates that the zones with mudcake are permeable. The caliper is off depth. How far off depth is it. The SP was run with the sonic log and is showing some bimetallic effects. At what depth are these anomalies. Where is the oil water contact on this example?

2. Calculate the logs that comprise Problem Log 7-1 (a and b). Use the Rwa approach. What is the pay zone thickness, porosity and water saturation? If this well is on a 40 acre spacing what is the total amount of oil in place in the pay zone?

The SP on the acoustic log and the specific acoustic time curves are off depth. How much off depth are they? Why is the acoustic SP a little different than the induction SP? Which is right?

3. On Problem Log 7-2 calculate the logs using the Rwa approach. Determine porosity and water saturation.

The shale travel time is 112 microsec/ft. How will this effect your calculational procedure?

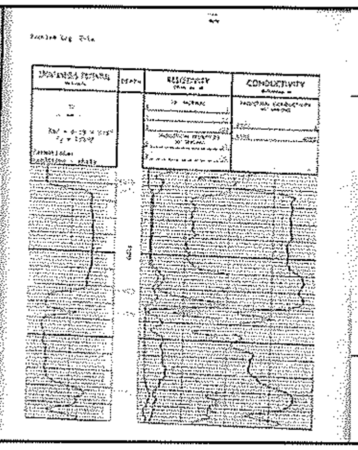
This is an oil bearing zone from South Louisiana. Why are the water saturations so different?

4. Problem Log 7-3 is a log over the Nodosa limestone. The SP and caliper are off the sonic log. This is one of the earlier induction electric logs (that is what the 37F40 means). Find the oil water contact. What will the tests at levels A and B produce?

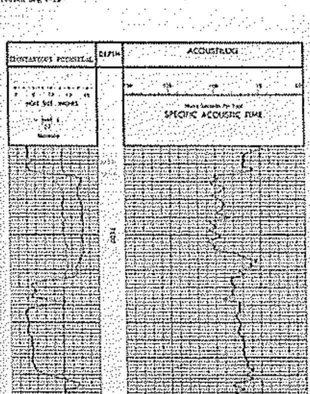
The bit size is 8 3/4 inches in diameter. How far off depth is the caliper log. The SP again exhibits bimetallism. At what depths do these effects occur.

NOTE: If you used the induction resistivity curves on some of these examples you may have missed the pay zones. A significant number of conversions from conductivity to induction resistivity are poor in the low resistivity range. I usually estimate 1 in 4 logs have bad resistivity / conductivity conversions

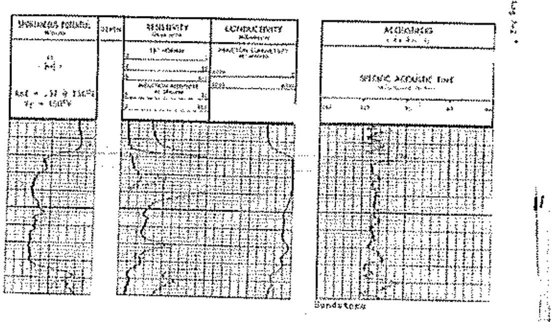
Problem Log 7-1a

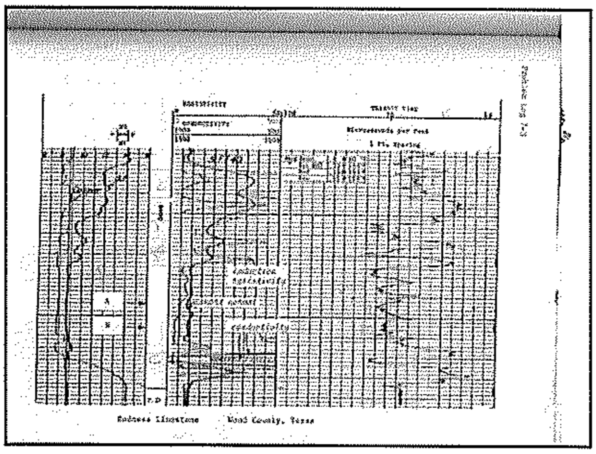


Problem Log 7-1b



Problem Log 7-2





HW NO 7; Rwa approach Chapter 7; 2 and 4 in HILCHIE TEXT and Chapter12; 12.3 in SPE TEXT and in the hand out sheet; Due Date; 1 July 2013

1. ... effects. At what depth are these anomalies. Where is the oil water contact on this ...

2. Calculate the logs that comprise Problem Log 7-1 (a and b). Use the Rwa approach. What is the pay zone thickness, porosity and water saturation? If this well is on a 40 acre spacing what is the total amount of oil in place in the pay zone?

   The SP on the acoustic log and the specific acoustic time curves are off depth. How much off depth are they? Why is the acoustic SP a little different than the induction SP? Which is right?

3. On Problem Log 7-2 calculate the logs using the Rwa approach. Determine porosity and water saturation.

   The shale travel time is 117 microsec/ft. How will this effect your calculational procedure?

   This is an oil bearing zone from South Louisiana. Why are the water saturations so different?

4. Problem Log 7-3 is a log over the Rodessa limestone. The SP and caliper are off the sonic log. This is one of the earlier induction electric logs (that is what the 5FF40 means). Find the oil water contact. What will the tests at levels A and B produce?

   The bit size is 8 3/4 inches in diameter. How far off depth is the caliper log. The SP again exhibits bimetalism. At what depths do these effects occur.

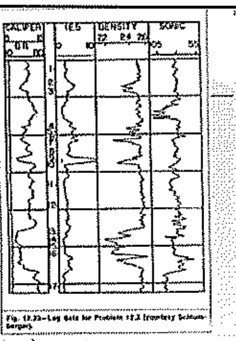


Fig. 12.23—Log data for Problem 12.3 (courtesy Schlumberger).

12.3 Induction/gamma ray, density, and sonic logs were recorded in oil-based mud of a U.S. gulf coast well that penetrates a sand/shale series. Tabulated below are log values for each of the levels numbered on the log of Fig. 12.23.

a. Calculate R_{wa} for each level using sonic log porosity.
b. Repeat the above calculations using density log porosity.
c. R_{wa} density differs slightly from R_{wa} sonic in certain zones (e.g., Zones 5, 6, 13, and 14). Explain the reason for this slight difference.
d. R_{wa} density differs drastically from R_{wa} sonic in Zones 1, 8, 11, 12, and 17. Explain the reason for this drastic difference.
e. What is the most probable value of formation water resistivity?
f. If the cutoff saturation is 50%, what are the probable pay zones?

Level	R_{IL} ($\Omega \cdot m$)	ρ_b (g/cm^3)	Δt ($\mu sec/ft$)
1	2.6	2.51	77.5
2	4.8	2.32	81
3	4.0	2.33	79.5
4	5.0	2.345	79.5
5	4.0	2.39	79.5
6	5.0	2.41	79.5
7	5.8	2.24	87
8	3.0	2.49	82
9	11.0	2.32	79.5
10	10.0	2.27	82.5
11	1.65	2.50	90
12	2.3	2.53	79.5
13	1.8	2.26	83.5
14	1.25	2.195	90
15	1.75	2.32	87.5
16	1.50	2.23	87.5
17	1.25	2.49	94

Problem 12.3
a. Zone 10: R_{wa} = 0.50 $\Omega \cdot m$.
b. Zone 10: R_{wa} = 0.65 $\Omega \cdot m$.
c. The petrophysical models used to calcula... and F.
d. The zones are very shaly.
e. R_w = 0.17 $\Omega \cdot m$.
f. Zones 7, 9, and 10.

CHAPTER 8 PROBLEMS

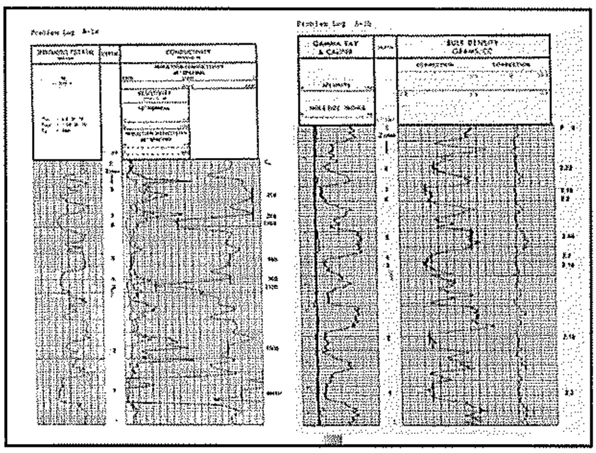
HW NO 8; Density LOG

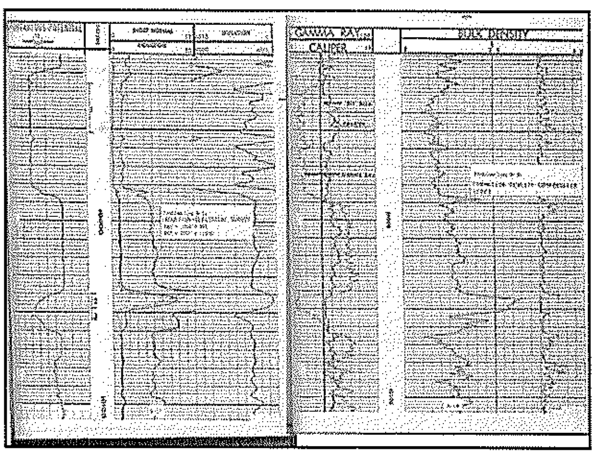
Do problem chapter 8; 8.1, 8.3 in HILCHIE TEXT and Chapter8; 8.7, and 8.8 in SPE TEXT

1. Problem log 8-1 has several zones picked to help you learn to pick zones. All potential zones have not been picked. Interpret problem logs 8-1a and 8-1b picking all the permeable zones. Each permeable bed isolated by shale beds should be considered a separate reservoir. Why is the Rw from the SP different than that from the Rwa technique? Why is there so much variation between the water saturations in the various hydrocarbon (oil) zones?

2. In problem log 8-2 the induction electric log and density log were run ... scaled in sandstone poros... porosity assuming all the zones were sandstone). The conductivity derived porosity was obtained ... The relationship is gotten from the Archie equations ... ar is the ... the hydrocarbon suppression on the SP. Why do the conductivity derived porosity and the density porosity separate above 10,900?

3. On problem logs 8-3a and 8-3b interpret zones 1-3. This is a Tertiary sequence usually considered to be sands and shales. Which zones on this Gulf Coast set of logs are hydrocarbon bearing. If you were told that there was a limestone (shell bed) which one would pick as this zone?





HW NO 8, Density Log
Do problem chapter 8; 8.1, 8.3 in HILCHIE TEXT and Chapter8; 8.7, and 8.8 in SPE TEXT
Due date; Friday 22 February 2013

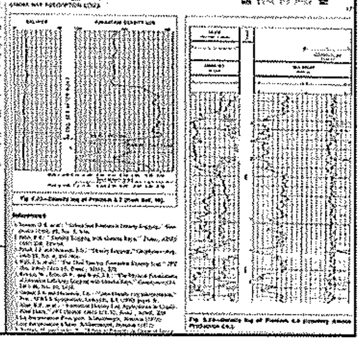
8.1 Fig. 8.23 shows two density logs run through sandstone Formation A in a gas injection well. Run 1 was made when the formation was fully saturated with water of 50,000 ppm salinity before gas injection. Run 2 was made several months after gas injection started. Estimate the gas saturation in the vicinity of the wellbore. The injected gas is mostly methane. Formation temperature and pressure are 100°F and 2,000 psia, respectively.

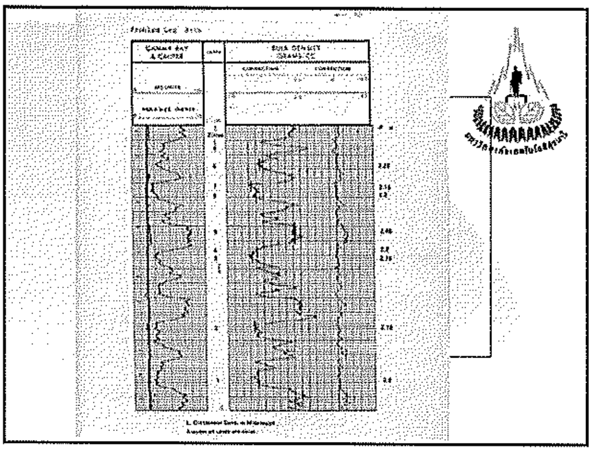
8.3 Refer to the density log of Fig. 8.24 in answering the following questions.

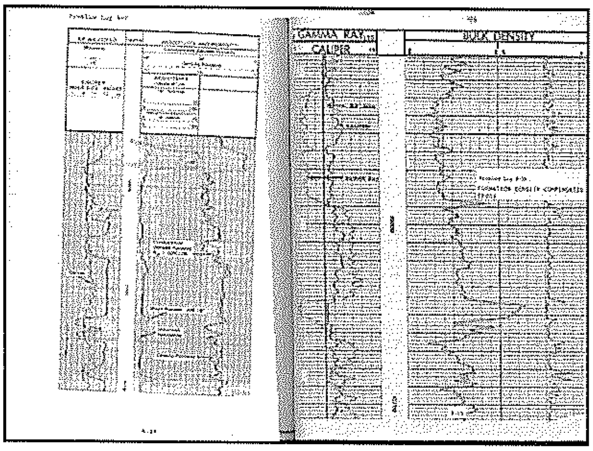
a. How representative is the log response at the levels marked with X's? Explain.

b. If the clean sands of the interval illustrated by the log are known to display a more-or-less constant porosity, give your best estimate of that porosity value.

c. Calculate a density porosity at Level Y. Explain why this value is different from that calculated in Part b.







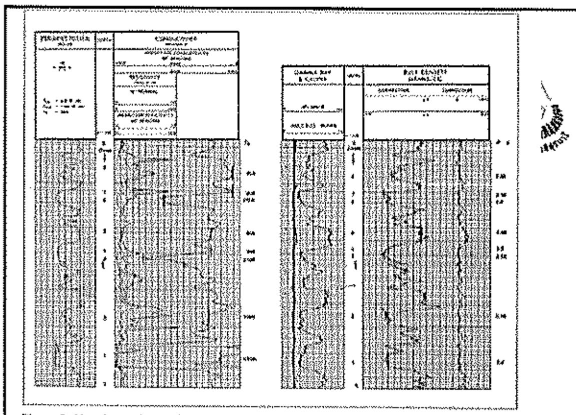
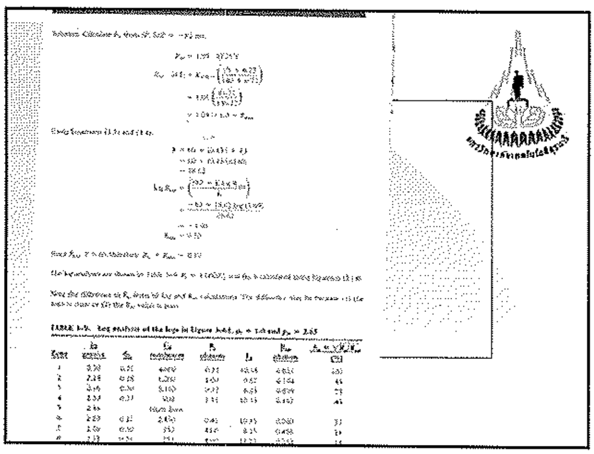
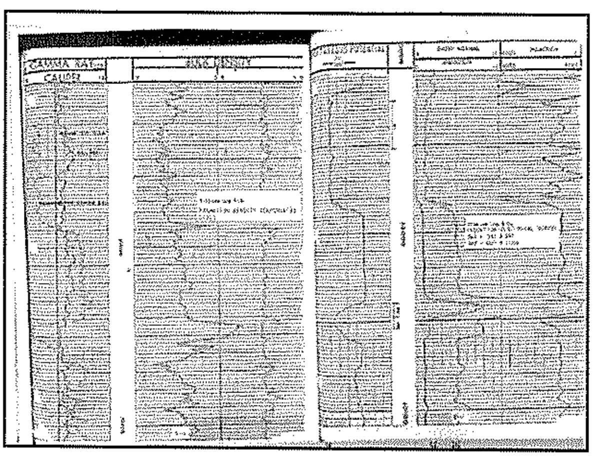
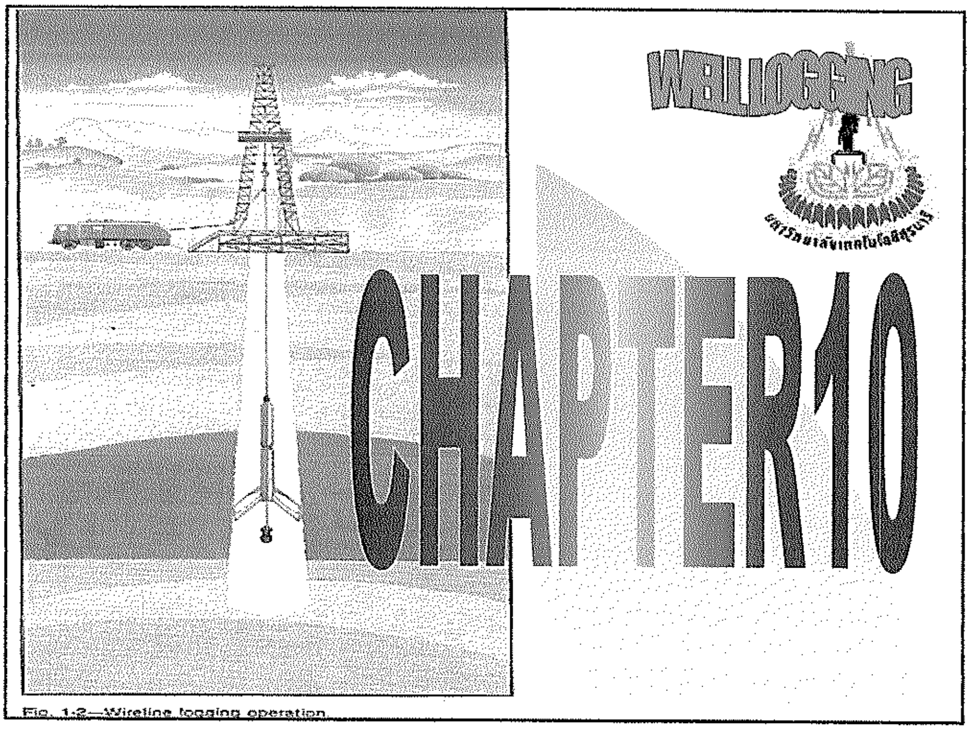
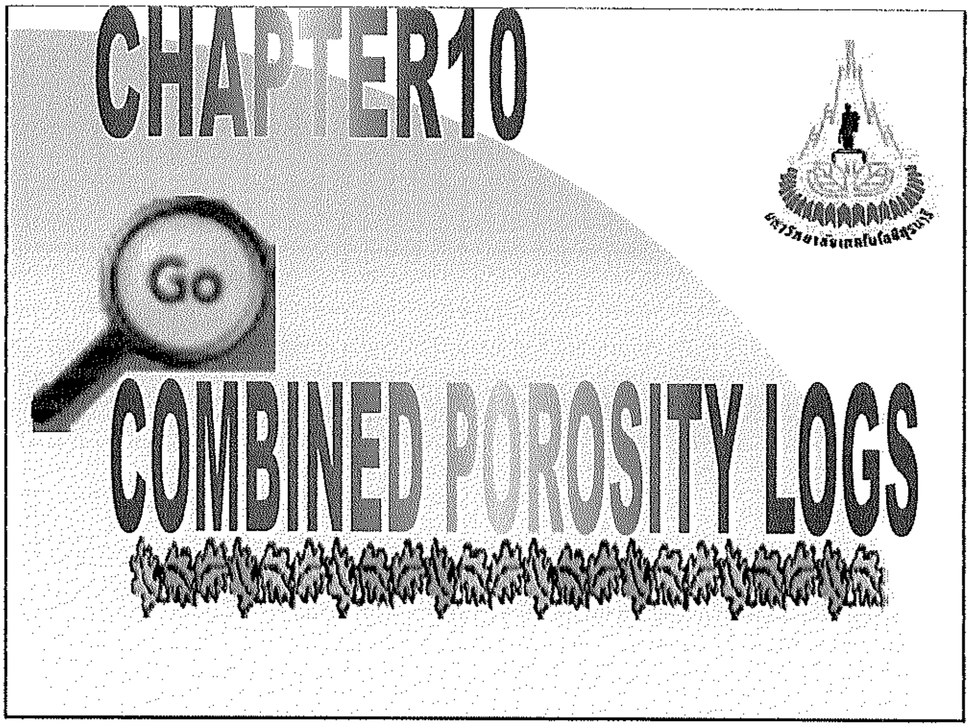


Figure 3-61. Openhole well logs for Example 3-19 (courtesy of D. W. Hilchie, Inc., Boulder, Colorado).





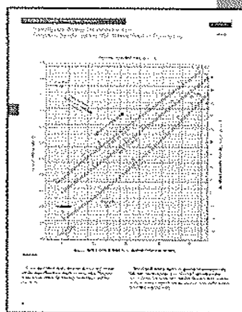

WELLLOGGING
มหาวิทยาลัยเทคโนโลยีสุรนารี
CHAPTER10
Fig. 1-2—Wireline logging operation.


CHAPTER10
มหาวิทยาลัยเทคโนโลยีสุรนารี
Go
COMBINED POROSITY LOGS

Introduction

Porosity combinations

- When using a single porosity measurement, lithology must be specified, through the choice of a matrix value, for the correct porosity to be calculated
- When using two or more measurements, lithology may be predicted (along with porosity), but with some ambiguity
- Measurement preferences (in order of choice):
  - Two measurements:
    - Neutron and Density
      - Quick-look Lithology and Porosity
    - Neutron and Sonic
    - Spectral density (bulk density and Pe)
    - Density and Sonic
  - Three measurements:
    - Neutron and spectral density
    - Neutron: Density, and Sonic
      - MID (Matrix Identifications) Plots
      - M-N Plots



Chapter 10 Combined Porosity Logs

for density log

$\rho_b = \phi \rho_f + V_{ls}\rho_{ls} + V_{dol}\rho_{dol}$

[illegible] functional.

$\rho_b = f(\phi, V_{ls}, V_{dol})$ — ①

for Neutron log.

$\phi_N = f(\phi, V_{ls}, V_{dol})$ — ②

and

$V_{ls} + V_{dol} + \phi = 1$ — ③

① + ② + ③ 3 [illegible] 3 Unknow. [illegible] Solution

or. Graphic Solution [illegible]

Cherty (Sandstone) dolomite

Limy (Limestone) dolomite.

COMBINED POROSITY LOGS

for. ϕ in C, [illegible]

1. Complex lithology

$\rho_b = \phi \rho_f + V_{ls}\rho_{ls} + V_{dol}\rho_{dol}$ —(10-1)

$\rho_b = f(\phi, V_{ls}, V_{dol})$ — 10.2

$\phi_N = f(\phi, V_{ls}, V_{dol})$ 10.3

$V_{ls} + V_{dol} + \phi = 1$ 10.4

Crossplot solve 3 eqs. 3 unknowns

[illegible] Density/Neutron

Fig 10.2 lithology [illegible] → ϕ [illegible] LS 21%. cherty (SS) Dolomite 21.5%

Sand $\rho_s \neq 2.65 (=2.7) \rightarrow$ d.S

Fig 10.3 [illegible] if LS $\phi = 16\%$. Sonic/Neutron

[illegible] if Sandy Dolomite $\phi = 14.5\%$

[illegible] Density/Neutron

Second ϕ acoustic/neutron $\phi \rightarrow$ low [illegible]

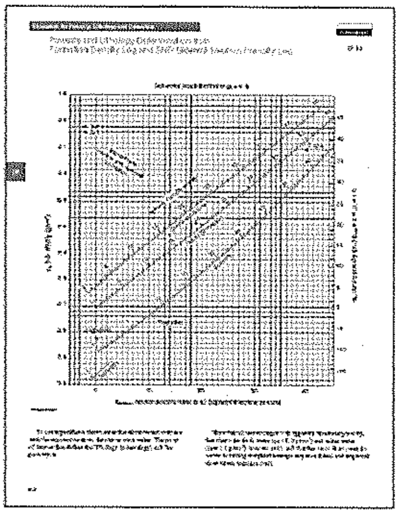
Shale $\phi_N \uparrow$ $\phi_D \downarrow$ Halite ϕ_D 40% ϕ_N 0%

Dolomites $\phi_N \uparrow$ $\phi_D \downarrow$ (neg.) ~ 15%. Separation 15%

Anhydrite ϕ_N 0 ~ -1%

porosity units

Neutron-Density crossplot



- Advantage:
  - Given two possible lithology pair solutions, the porosity remains relatively invariant between the solutions
  - The combination of neutron and density is the most common of all porosity tool pairs
- Disadvantage:
  - In rough holes or in heavy drilling muds, the density data might be invalid

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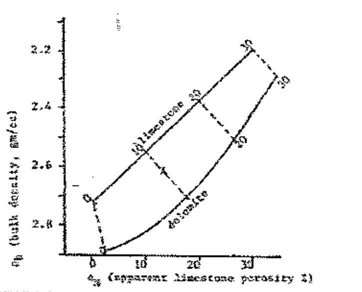
Equations 10-2, 10-3 and 10-4 allow us mathematically to solve three equations with three unknowns. This can be done mathematically or i be done graphically. Figure 10-1 shows a porosity log crossplot of a density and compensated neutron for a limestone dolomite mixture. lines marked dolomite and limestone are for 100% of these minerals a all combinations of limestone and dolomite will result in the data f between the two lines. The major porosity lines (e.g. 0, 10, 20, an are shown.

Figure 10-1 Density/Neutron crossplot for limestone and dolomite



Point A, which has a bulk density of 2.62 gm/cc and an apparent lime porosity of 14%, is a limy dolomite with a porosity of 10%.

Point A, If Limy Dolomite φ (porosity)=10%

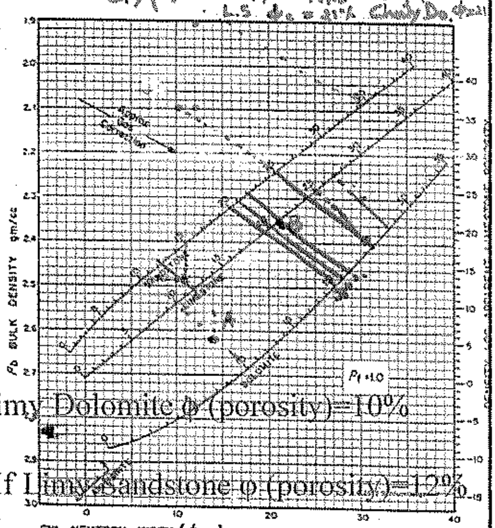
Figure 10-2 is a conventional density/neutron (Schlumberger CNL) cro chart. In addition to the limestone and dolomite lines are lines for stone and anhydrite. The mathematical game is still the same as int for Figure 10-1. The crossplot is a solution of three equations and unknowns. The variables allowed are porosity plus two lithtypes, (d limestone and dolomite, sandstone and limestone, sandstone and dolom Point B on Figure 10-2 which represents a density of 2.36 gm/cc and limestone porosity of 21.5% could be a limestone with 21% porosity o it could be a cherty (sandstone) dolomite with a porosity of 21.5%. latter porosity is obtained by joining the 21 and 22 % porosity line the sandstone and dolomite lines and finding B between them. This e shows that we can find the lithology from this crossplot if we know lithology from some other source. The porosity we determine from this

Point C, If Limy Sandstone φ (porosity)=12%

Point A. Limy Dolomite

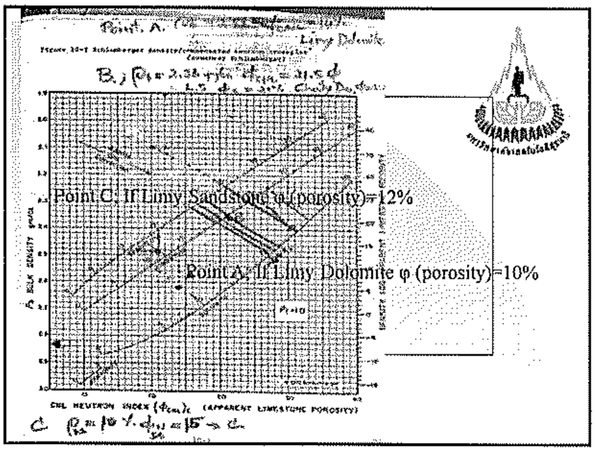
Figure 10-2 Schlumberger density/compensated neutron crossplot (courtesy Schlumberger)

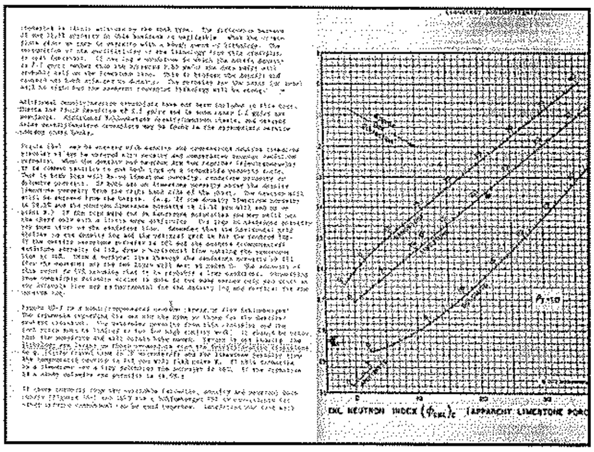
B, ; ρ_b = 2.36 g/cc ϕ_{CNL} = 21.5 φ
L.S ϕ_c = 21% Cherty Do, φ = 21

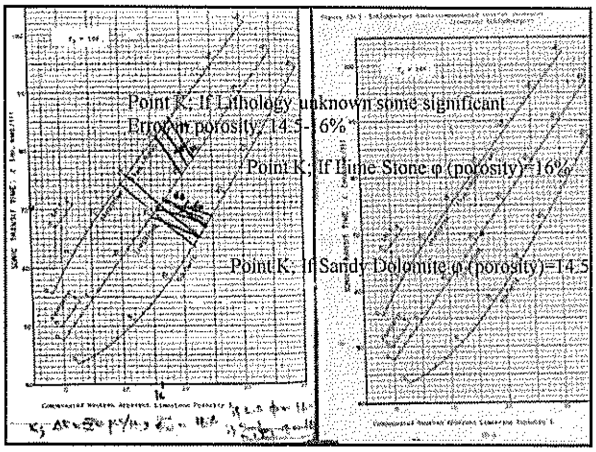


C ρ_{ss} = 10 % ϕ_N = 15 → C

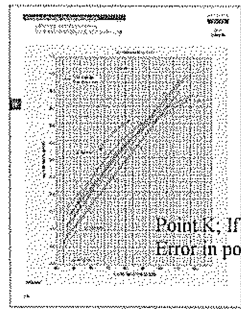
10-3







Sonic-Density crossplot



- Advantage:
  - Potential reservoirs plot along the closely spaced lithology lines, while shales tend to fall toward the lower right of the plot
  - Quite useful for determining some evaporite minerals
- Disadvantage:
  - The choice of the lithology pair has a significant effect on the estimation of the porosity
  - The lithology lines are closely spaced, so any uncertainty in the measurements produces large changes in lithology and porosity estimates

Point K: If Lithology unknown some significant
Error in porosity; 14.5-16%

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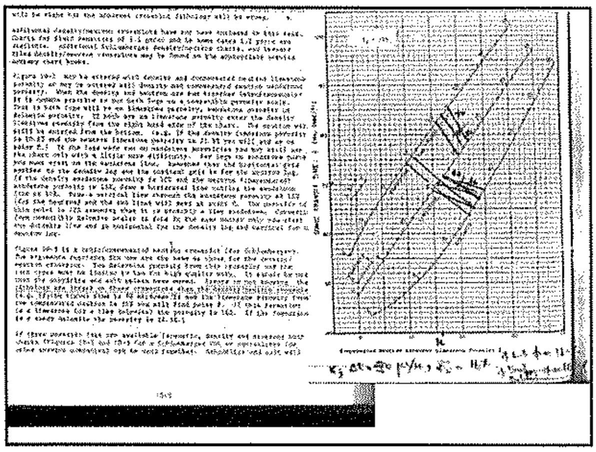
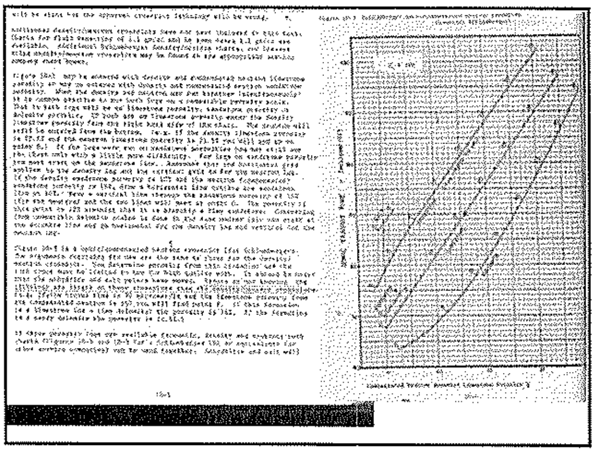
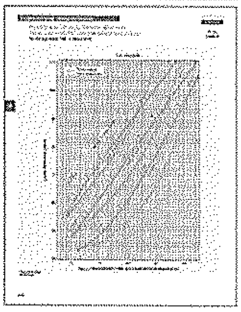




Sonic-Neutron crossplot



- Advantage:
  - Given two possible lithology pair solutions, the porosity remains relatively invariant between the solutions
  - The sonic is less sensitive to rough holes than the density
- Disadvantage:
  - The combination of sonic and neutron data is not common

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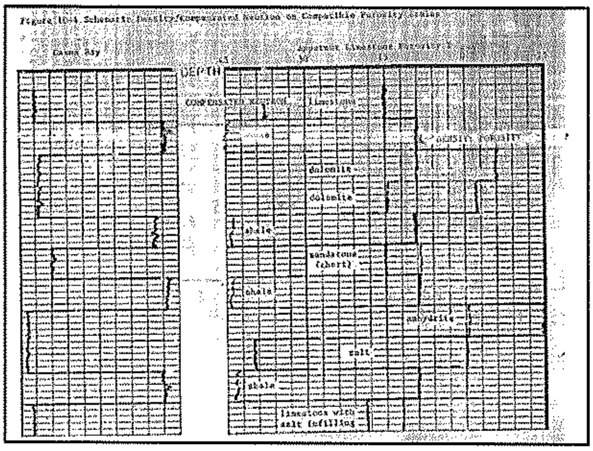
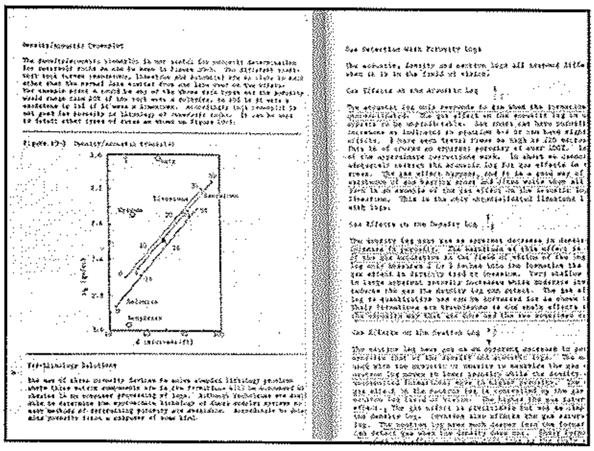
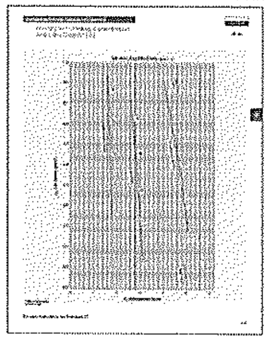




Density/Acoustic Crossplot

Gas Detection With Porosity Logs

Density-Photoelectric crossplot



- Advantage:
  - Both measurements are maid with the same logging tool; both will be available in newer wells
- Disadvantage:
  - The choice of the lithology pair has a significant effect on the estimation of the porosity
  - In rough holes or in heavy drilling mud the data may be invalid
  - The Pe will not be present in wells logged before 1978

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Density & Neutron log

Fig. 10.4

Limestone ϕ_N, ϕ_d read on LS scale Same

Shale $\phi_N \uparrow$ read high $\phi_d \downarrow$

Dolomite $\phi_N > \phi_d \approx 15\%$

[illegible]

$\phi_d \rightarrow$ negative

Chert, Sand Stone $\phi_N < \phi_d \approx 6\%$

Dolomite or Sand $\phi = \frac{\phi_N + \phi_d}{2}$

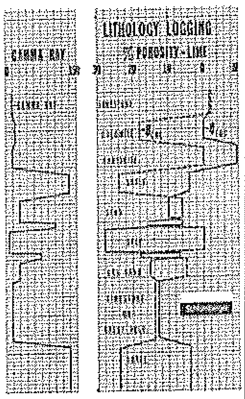
Anhydrite $\phi_N \approx 0, -1\%$

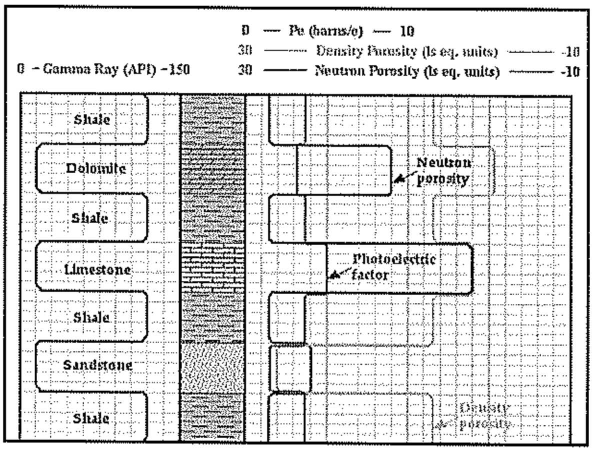
$\phi_N > \phi_d \approx 15\%$

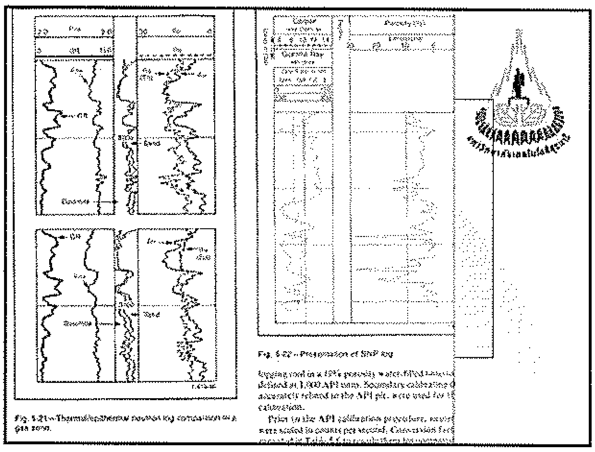
[illegible]

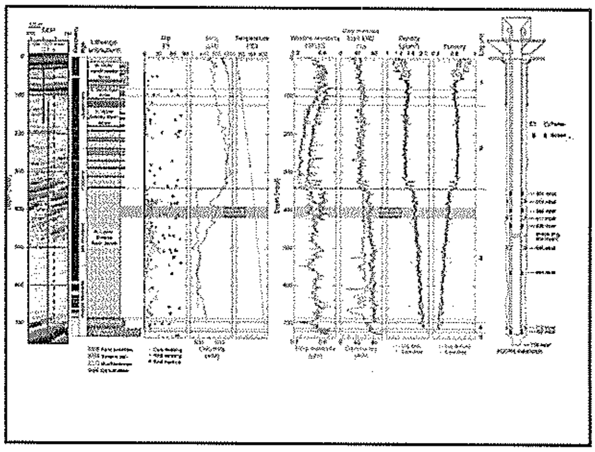
Salt or Halite $\phi_N \approx 0\%$

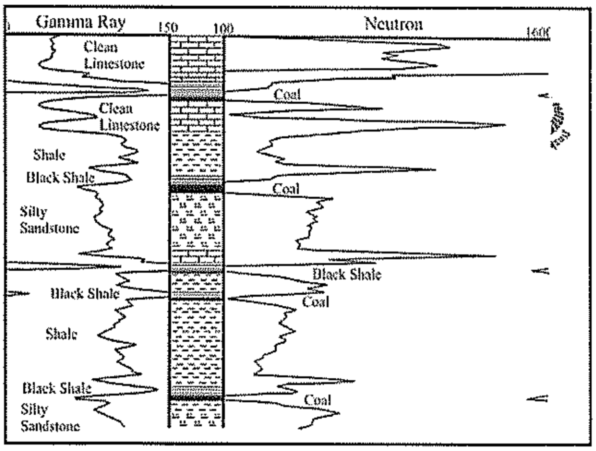
$\phi_d > \phi_N \approx 40\%$

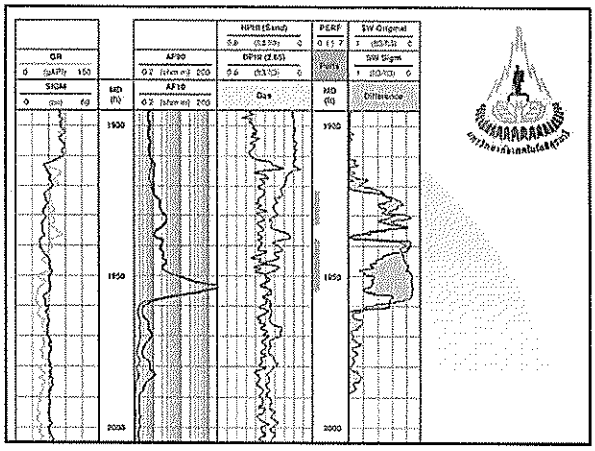


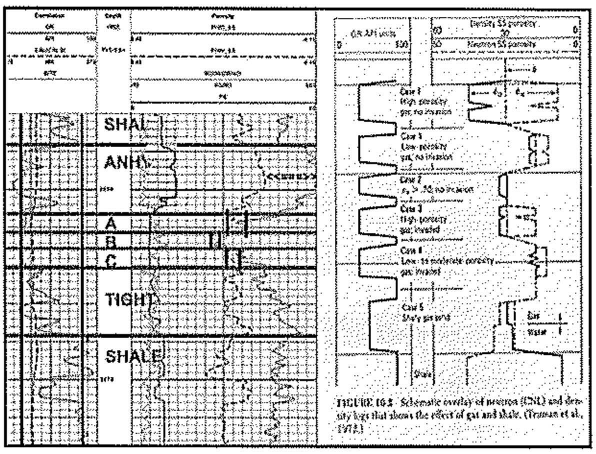


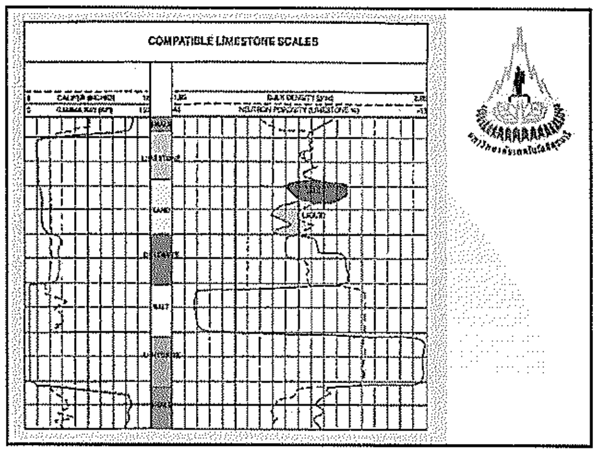


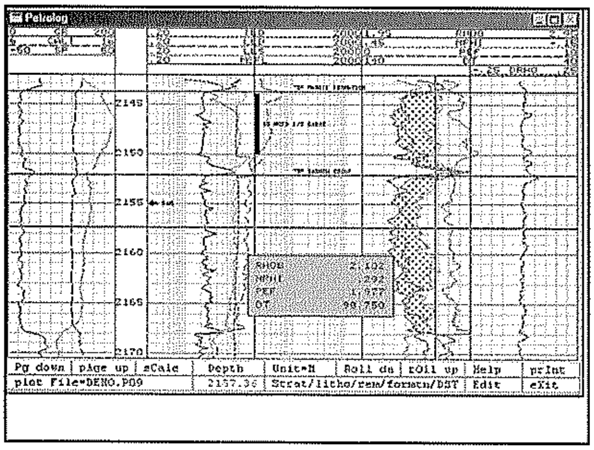


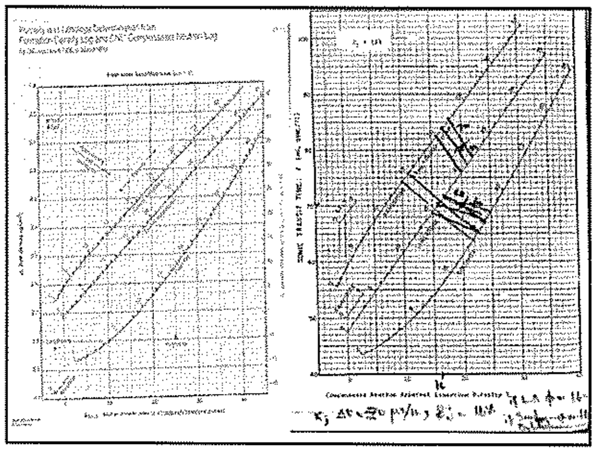

Gamma Ray
150
100
Neutron
Clean Limestone
Coal
Clean Limestone
Shale
Black Shale
Coal
Silty Sandstone
Black Shale
Black Shale
Coal
Shale
Black Shale
Coal
Silty Sandstone

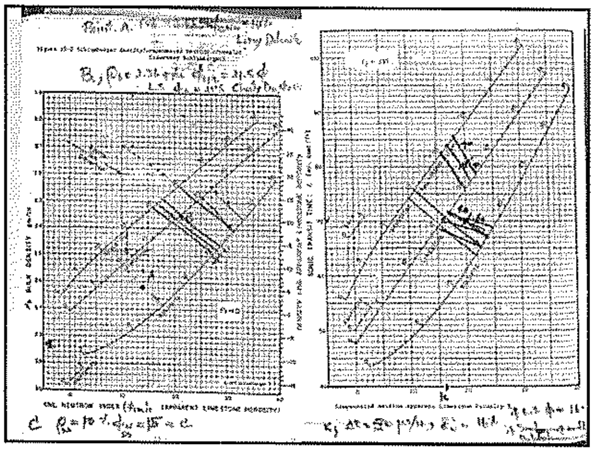

GR
SIGM
MD
AF90
AF10
NPHI (Sand)
DPHI (2.65)
Gas
PERF
SW Original
SW Sigm
Difference
1900
1950
2000

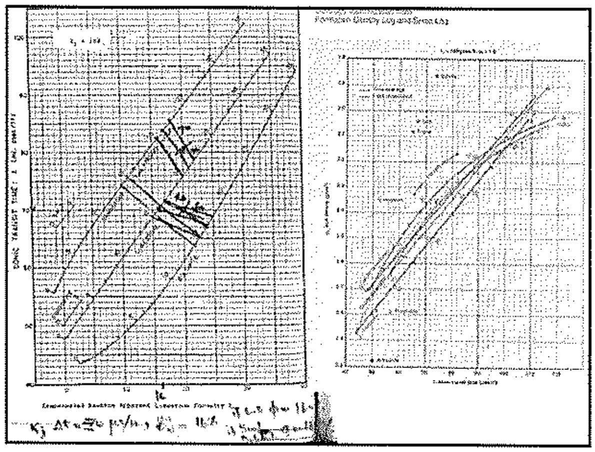

SHALE
ANHY
A
B
C
TIGHT
SHALE

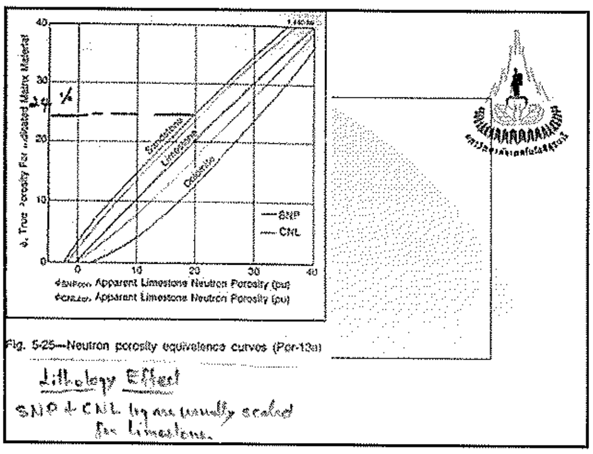

COMPATIBLE LIMESTONE SCALES

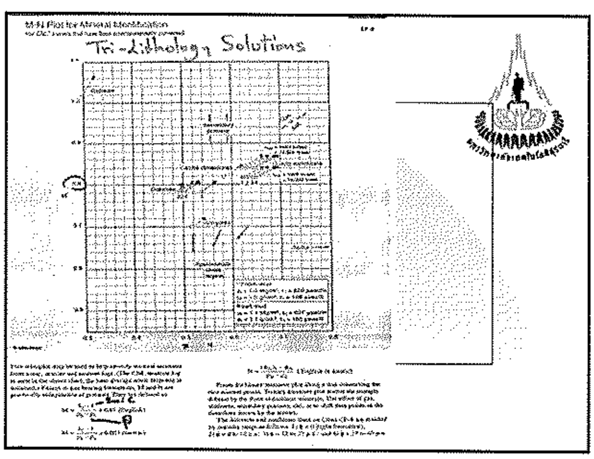

Petrolog
plot File=DEMO.P09








Sandstone
Limestone
Dolomite
SNP
CNL
Apparent Limestone Neutron Porosity (pu)
Fig. 5-25—Neutron porosity equivalence curves (Per-13a)
Lithology Effect
SNP + CNL log are usually scaled for limestone.


M-N Plot for Mineral Identification
Tri-Lithology Solutions

Gas Detection ϕ_s + ϕ_N Fig 10-15

in Shallow uncompact formation

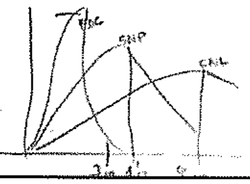
ϕ_s ↑ overresponds to the gas.
Δt

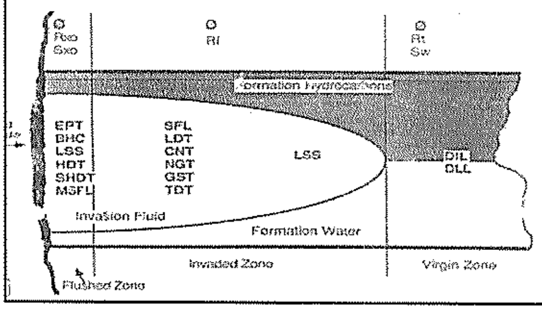
Gas Detection from ϕ_s & ϕ_d

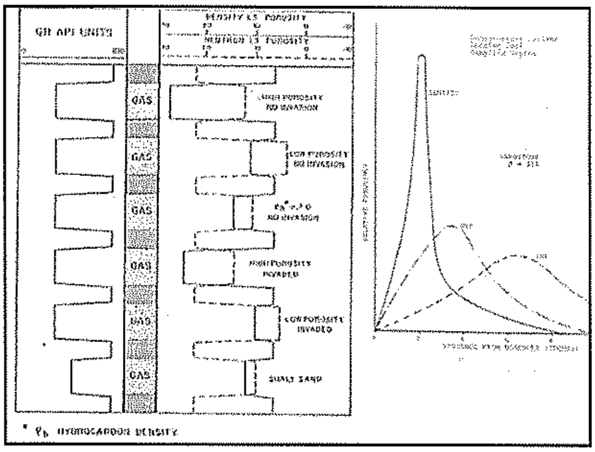
when Invasion is significant ϕ_d Fig 10-16

Respond ...

when Uncompact formation ϕ_s, Δt overresponds.







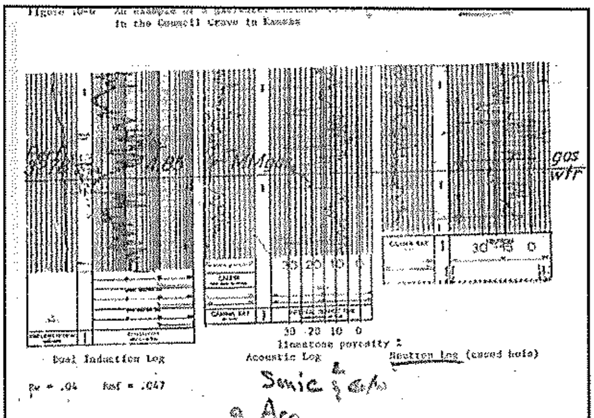
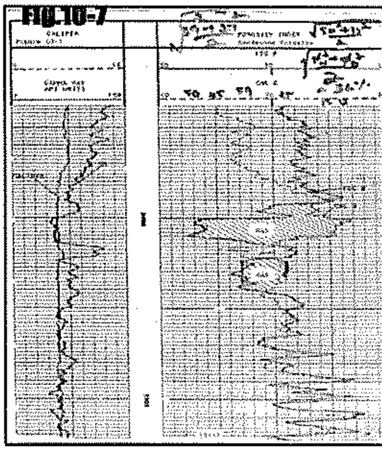
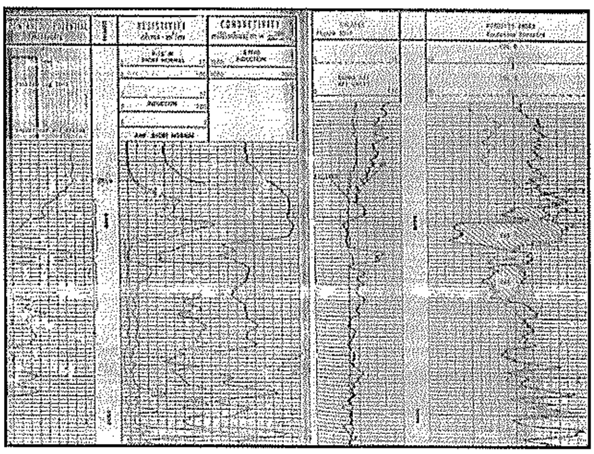
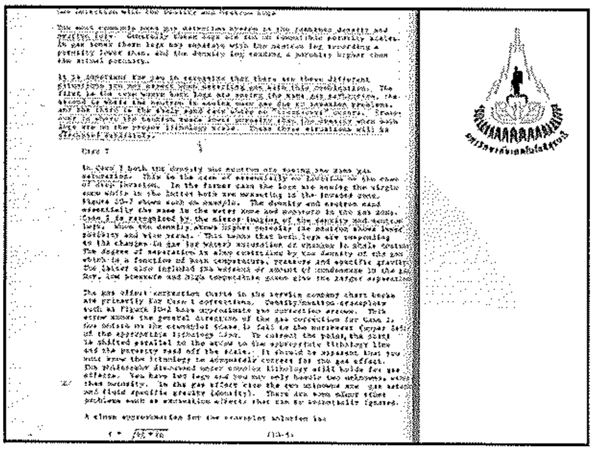


FIG.10-7







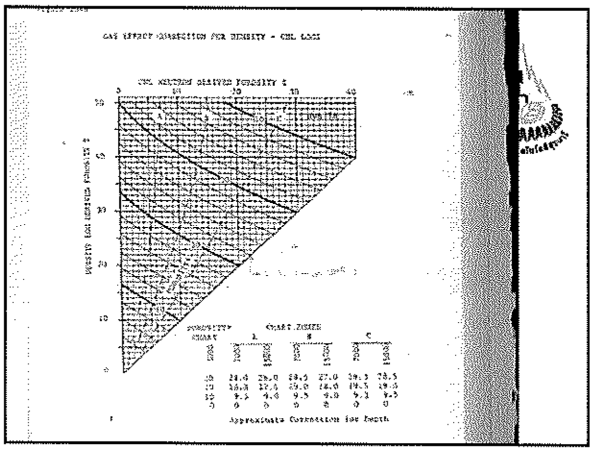
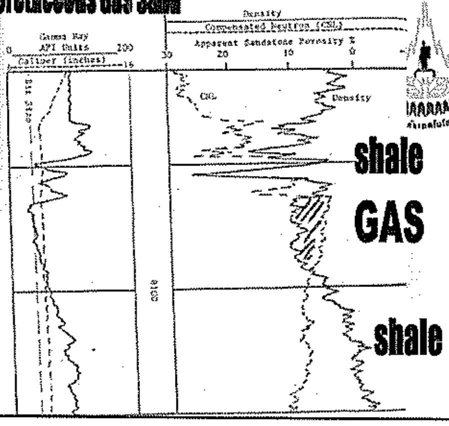
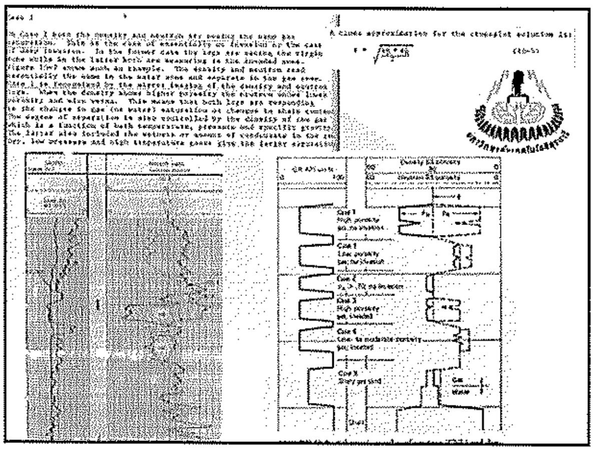


Fig.10-13 Cretaceous Gas Sand





Density/Acoustic Crossplot Fig 6.2
not good for ϕ or Reservoir Rock
good for other rocks + mineral.

Tri-Lithology Solution

GAS DETECTION

$\phi_S \uparrow$, $\phi_D \uparrow$, $\phi_N \downarrow$ Gas Effect

most commonly use FDC & CNL

CASE I Both seeing Gas.
Cross over $\phi_D \uparrow$, $\phi_N \downarrow$ Mirroring
$\phi = \sqrt{\frac{\phi_D^2 + \phi_N^2}{2}}$ Fig. 10-7, 10-8, 10-9

CASE II Cross Over but don't mirror
Neutron ... Fig 10-10
Density ... Invasion Zone
Use ϕ_D for ϕ

CASE III Shaly Formation
Shale effect ... ϕ_D, ϕ_N
Use Gamma + $\phi_N - \phi_D$ plot. Fig 10-13
or Chapter 13 V.S gamma Fig 10-14

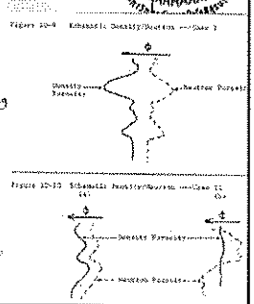
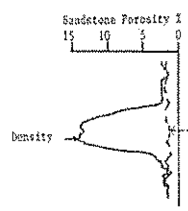


Figure 10-12 A schematic density/neutron Case II



A Case 1 gas correction reduces the porosity to the normal 9% porosity cutoff. The porosity of the formation is in the 13 to 14% range.

Neutron-Density: Special Case

- Gas detection:
  - Density porosity is too high
  - Neutron porosity is too low
  - Neutron porosity < Density porosity
  - Cross-over
  - Be aware, cross-overs may also be caused by lithological differences as an effect of the scaling

Porosity of a gas-bearing formation

$$\phi_{ND} = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}} \approx \frac{1}{3} \times \phi_N + \frac{2}{3} \times \phi_D$$

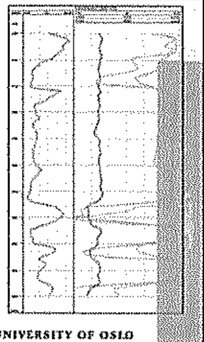


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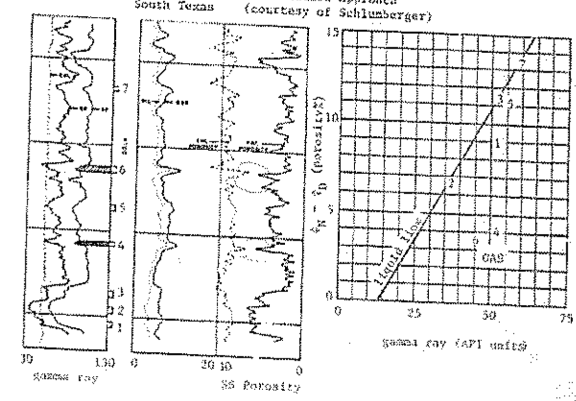
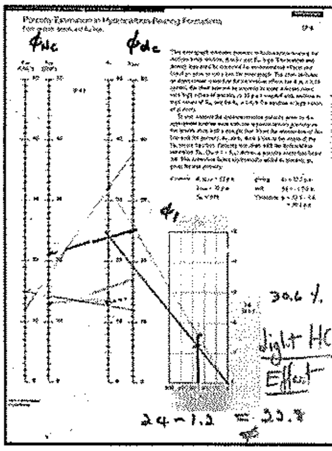
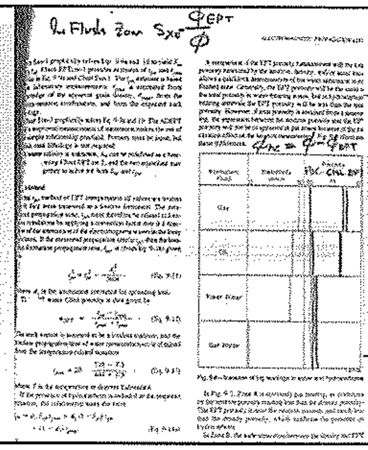
Figure 10-14 Case III gas identification approach South Texas (courtesy of Schlumberger)







GAS EFFECT CORRECTION FOR DENSITY − CNL LOGS

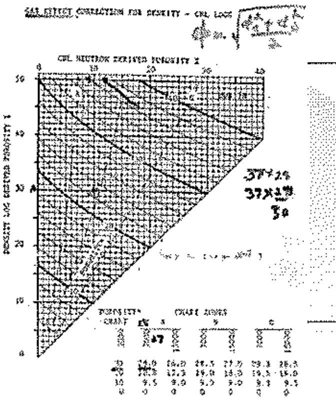
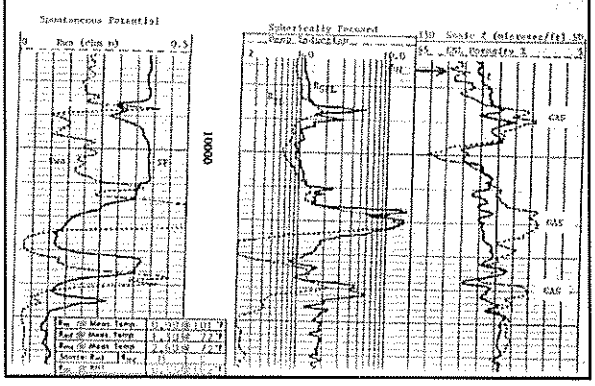


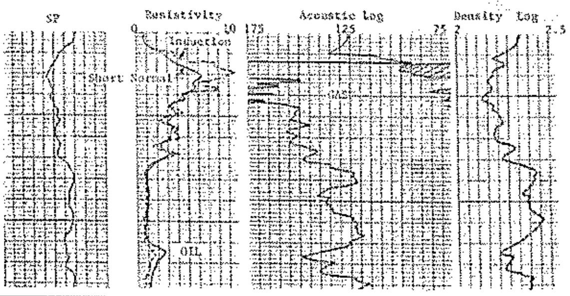
Figure 10-15 A compensated neutron and sonic log (Schlumberger) on the Louisiana Gulf Coast showing gas sands.

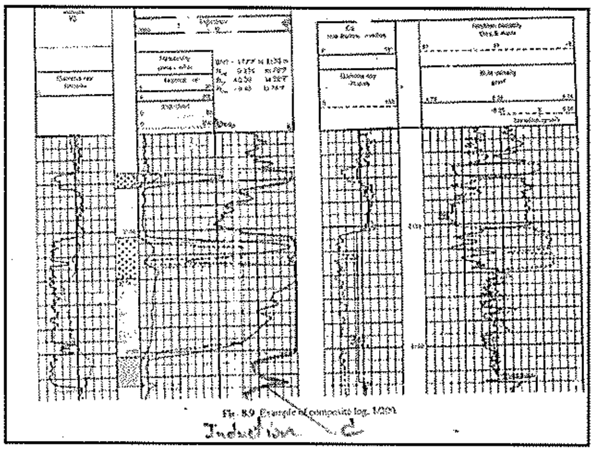


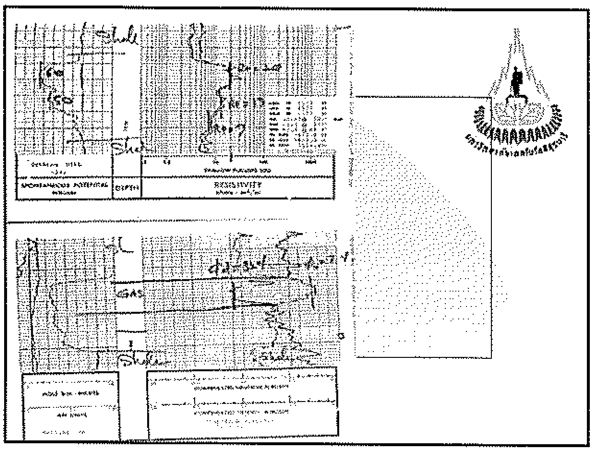
Gas Detection with the Acoustic and Density Logs

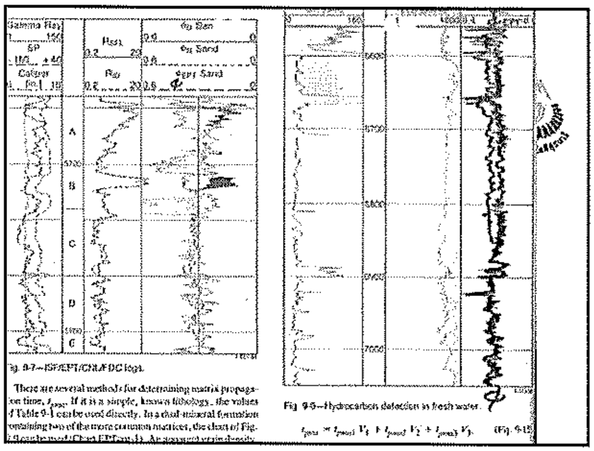
The only reliable detection of gas with the acoustic/density combination is when the acoustic log responds to the gas (in an uncompacted formation) and the invasion is significant enough to prevent the density from responding. Figure 10-16 shows such an example from offshore Louisiana.

Figure 10-16 An acoustic/density log showing a gas zone (offshore Louisiana)

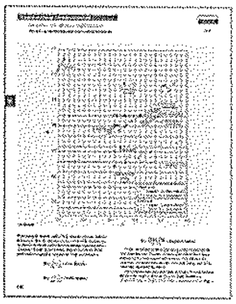








M-N Lithology plots



- Three-measurement lithology technique
- Combination of the three porosity measurements
- Single mineralogy
- Binary mixtures
- Ternary mixtures

$$M = \frac{\Delta t_f - \Delta t}{\rho_b - \rho_f} \times 0.01 \text{ or } 0.003 \qquad N = \frac{\phi_{Nf} - \phi_N}{\rho_b - \rho_f}$$

English Metric

Δt = from log $\quad$ Δt_f = formation fluid

ρ_b = from log $\quad$ ρ_f = formation fluid

ϕ_N = from log $\quad$ ϕ_{Nf} = fluid, usually 1.0

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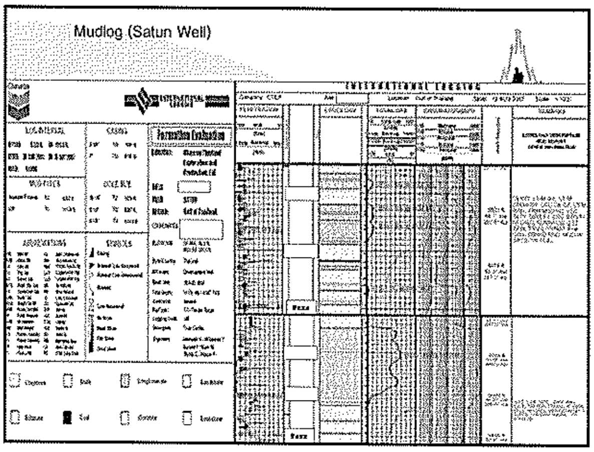
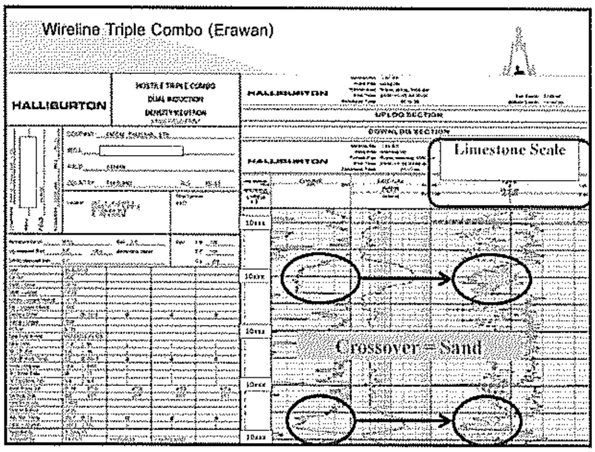
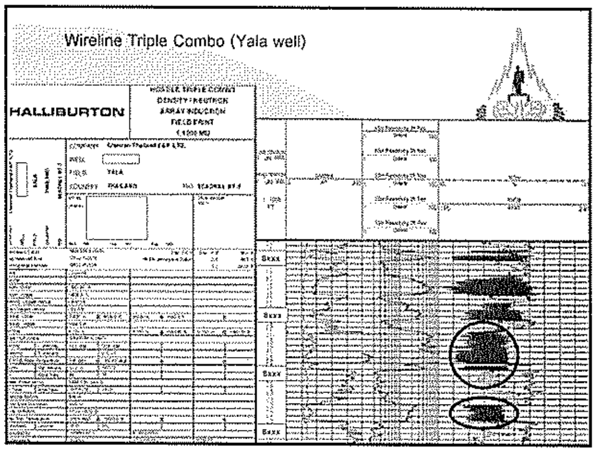
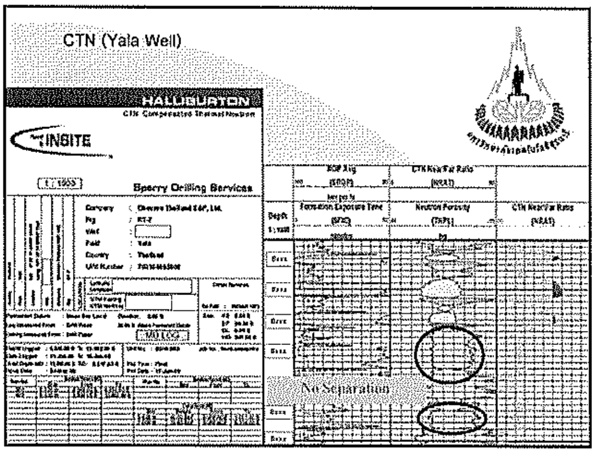
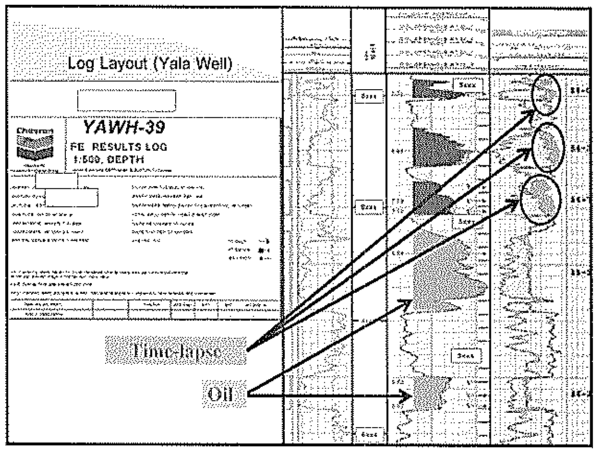
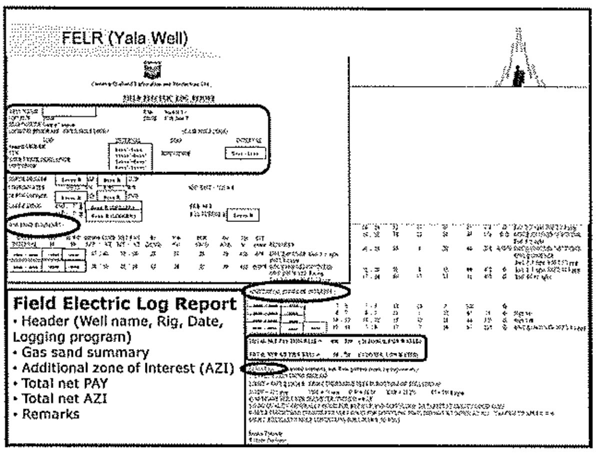


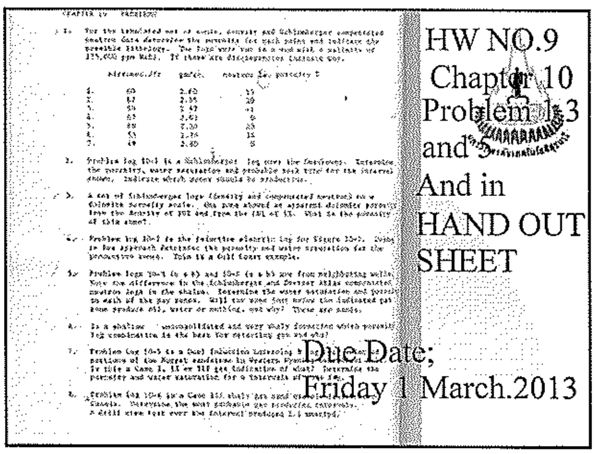

Wireline Triple Combo (Erawan)
HALLIBURTON
Limestone Scale
Crossover = Sand

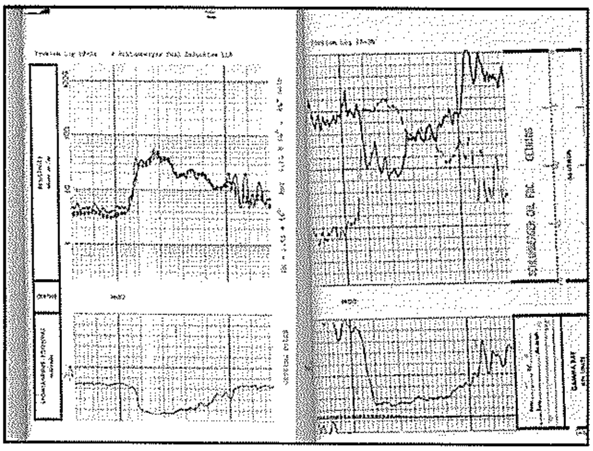

Wireline Triple Combo (Yala well)
HALLIBURTON

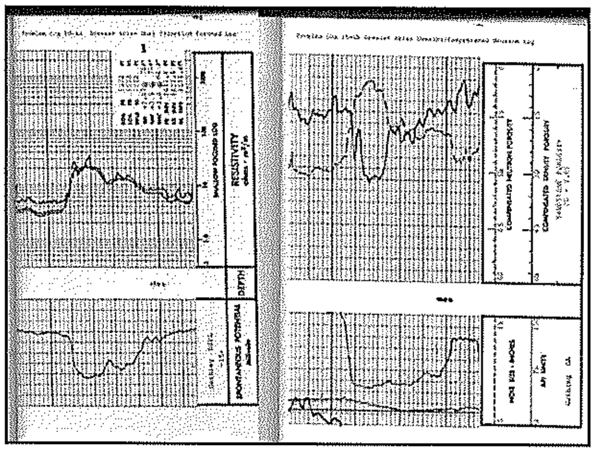

CTN (Yala Well)
HALLIBURTON
INSITE
Sperry Drilling Services
No Separation

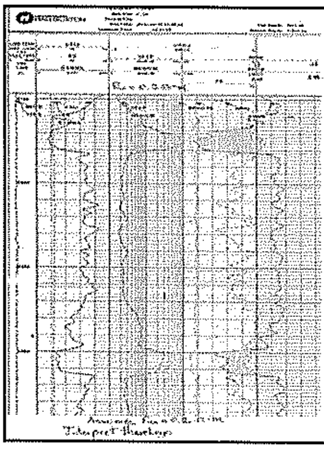

Log Layout (Yala Well)
YAWH-39
FE RESULTS LOG
1:500, DEPTH
Time-lapse
Oil


FELR (Yala Well)
Field Electric Log Report
• Header (Well name, Rig, Date, Logging program)
• Gas sand summary
• Additional zone of Interest (AZI)
• Total net PAY
• Total net AZI
• Remarks

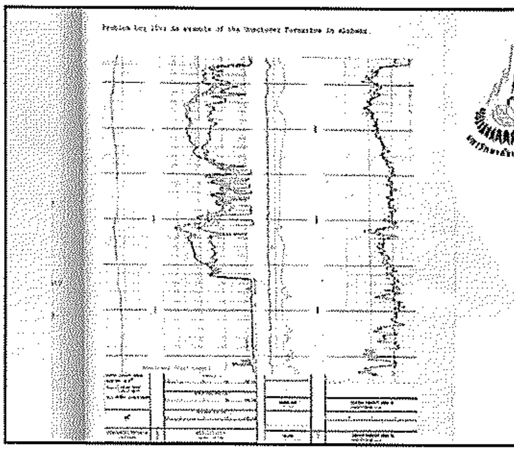

HW NO.9
Chapter 10
Problem 1-3
and
And in
HAND OUT
SHEET
Due Date;
Friday 1 March.2013

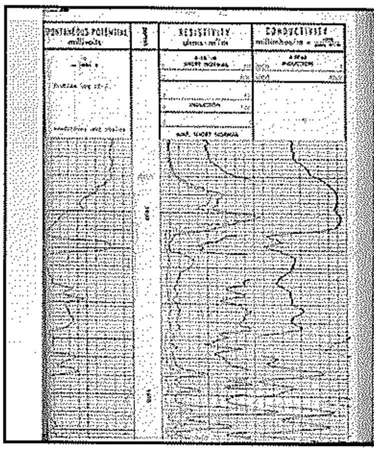


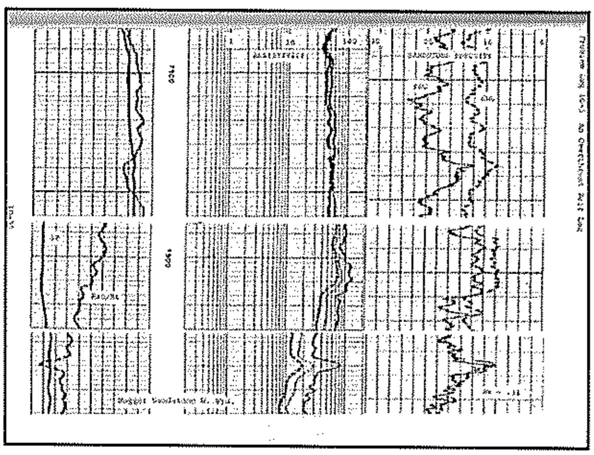




Interpret the logs
Assuming clean
Sand Stone and
Rw=0.2Ω-m







WELL LOGGING

CHAPTER1

CHAPTER12

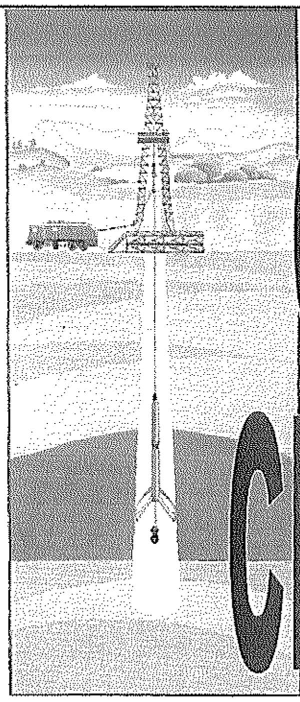


Fig. 1-2—Wireline logging operation.

434359,505359 WELL LOGGING 2012(3/2554)

COURSE OUTLINES

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)

Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.

Resistivity Device(2 hrs.)

Spontaneous Potential (SP) Log(2 hrs.)

Induction Electric and Dual Induction Logs(2 hrs.)

Acoustic , Gamma Ray and Caliper Logs(2 hrs.)

Quantitative Analysis –Part I (2 hrs.)

Density, and Neutron Logs(3 hrs.)

Combined Porosity and Lithology logs Determinations(2 hrs.)

Focused Resistivity Logs (2 hrs

QUICKLOOK Interpretations(3 h

Shaly Sand Interpretations(3hrs.)

Case Hole Logging(3 hrs.)

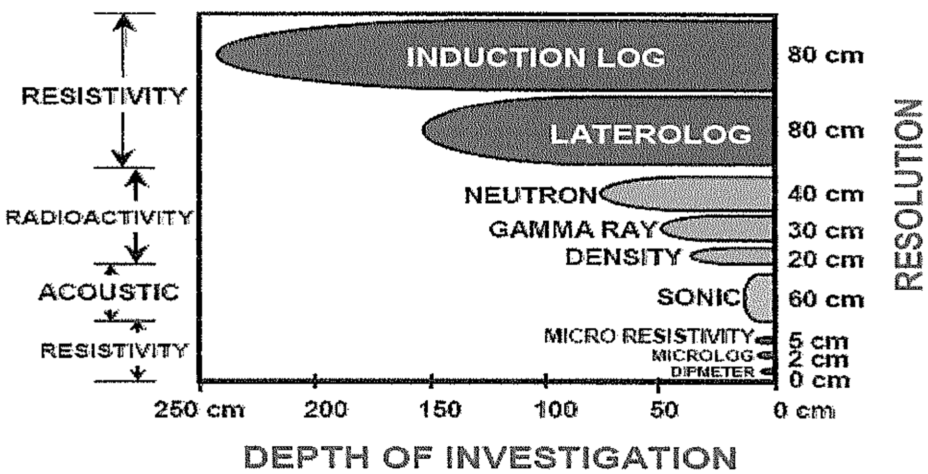
Computer Processing of well Logs(1 hr.)

Fracture Detection with Well Logs(1 hr.)

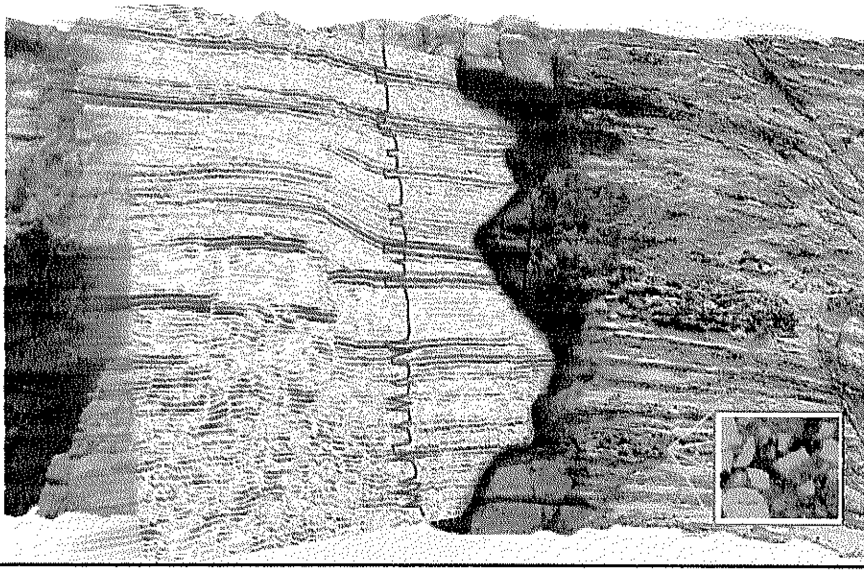
CHAPTER11

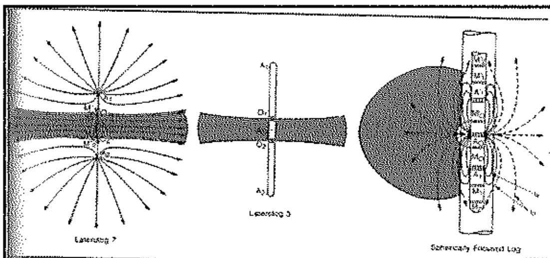
FOCUSES RESISTIVITY LOGS

Logging Tools



Scales Of Observation

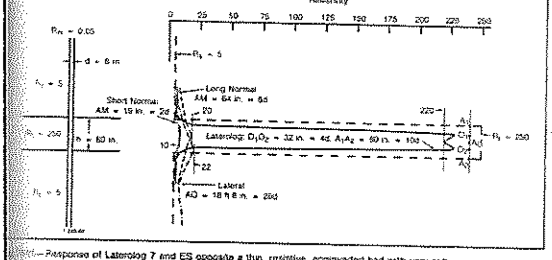




—Schematics of focusing electrode devices.

…ing into the formation (Fig 7-10). Symmetrical- …d on either side of the central A_0 electrode are … long (about 5-ft) electrodes, A_1 and A_2, which …orted to each other. A current, i_0, flows from the …ectrode, whose potential is fixed. From A_1 and A_2 … a bucking current, which is automatically adjusted …ntain A_1 and A_2 at the potential of A_0. All elec- … of the sonde are thus held at the same constant potential. The magnitude of the i_0 current is then proportional to formation conductivity.

The i_0 current sheet is constrained to the disk-shaped area. The thickness, O_1O_2, of the current sheet is usually about 12 in., much thinner than for the LL7 device. As a result, the LL3 tool had a better vertical resolution and shows more detail than did the LL7 tool. Furthermore, the influences of the borehole and of the invaded zone were slightly less.



—Response of Laterolog 7 and ES opposite a thin, resistive, noninvaded bed with very salty … determinations).

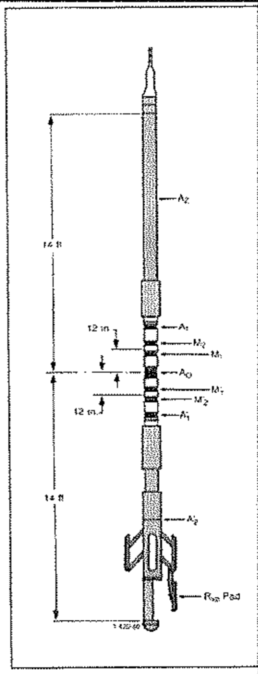


Fig. 7-12—Schematic diagram of the Dual Laterolog tool

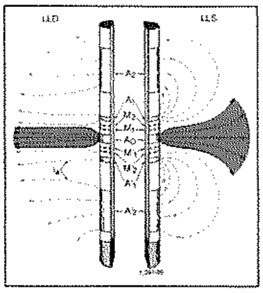


Fig. 7-13—Schematic of the Dual Laterolog.

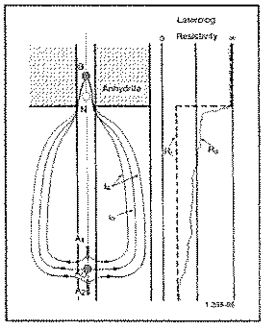
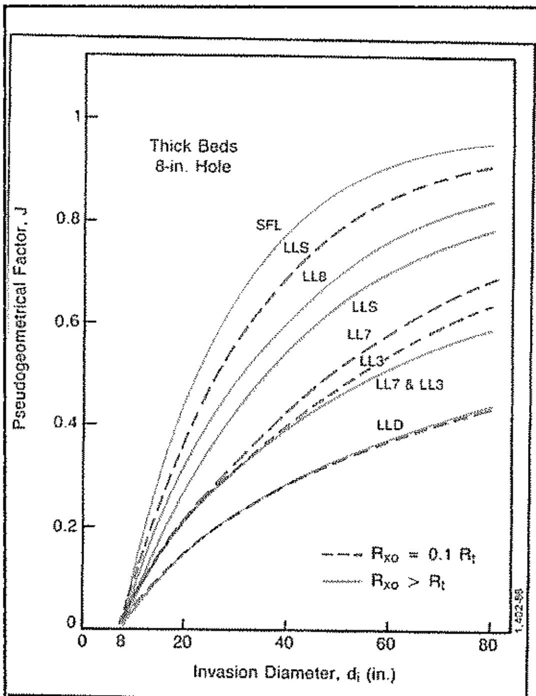


Fig. 7-14—Principle of Delaware effect.



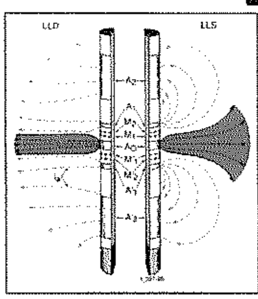


Fig. 7-13—Schematic of the Dual Laterolog.

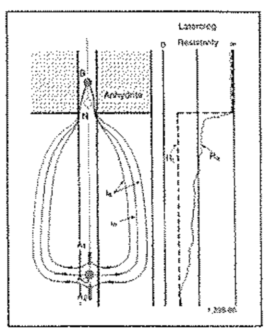


Fig. 7-14—Principle of Delaware effect.

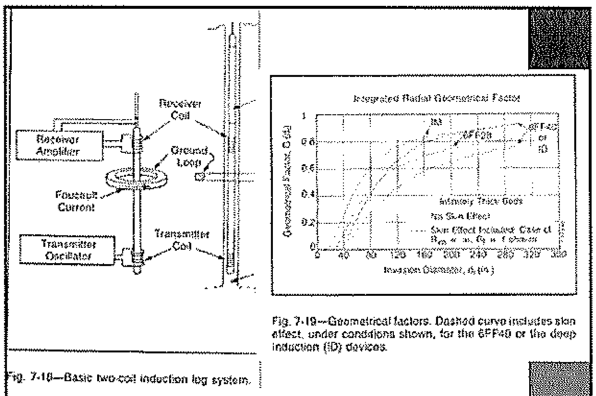
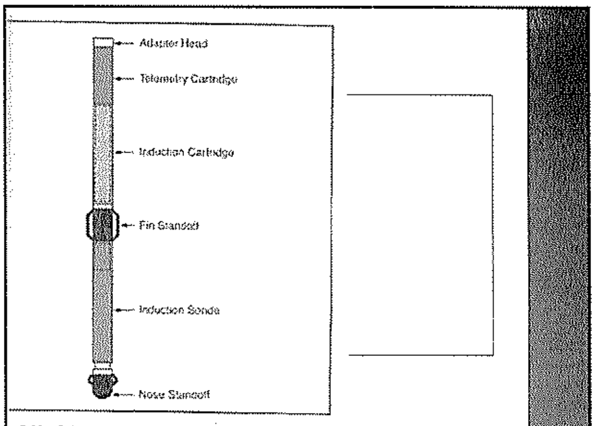


Fig. 7-19—Geometrical factors. Dashed curve includes skin effect, under conditions shown, for the 6FF40 or the deep induction (ID) devices.

Fig. 7-18—Basic two-coil induction log system.



7-25—Schematic of the Phasor Induction SFL tool.

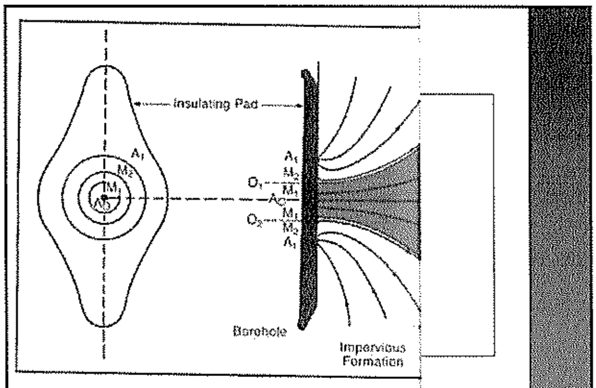
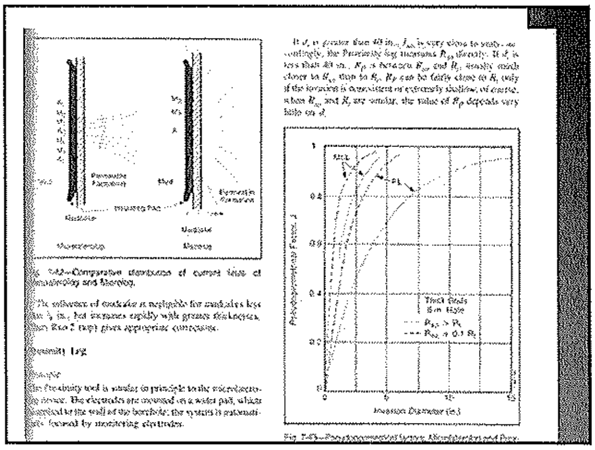


Fig. 7-41—Microlaterolog pad showing electrodes (left) schematic current lines (right).



Chapter 11. FOCUSED RESISTIVITY LOGS

① Laterolog

วัด Rt in salt mud: Laterolog 7, Laterolog 3, Dual Laterolog

วัด Ri: Laterolog 8 (shallow, thin bed), Spherically Focused Log (SFL)

② Micro-Resistivity Logs วัด Rxo

- Microlog: Normal 2", Inverse 1×2" (detect mud cake)
- Micro-Focused Resistivity (Rxo) Logs: Microlaterolog (MLL) วัด Rxo in salt mud; Proximity Log (PL) วัด Rxo in fresh mud (pad-type, where mud cake is thick); Micro-Spherically Focused Log (Microlaterolog and Proximity logs)

Chapter 11. FOCUSED RESISTIVITY

TABLE 7-1. Classification of ...

Micro · Flushed Zone (R_{xo}): Microlog, Microlaterolog, Proximity Log, Microspherically Focused Log (MSFL)

Laterologs วัด Rt

① Laterologs วัด Rt in salt base mud
② Microlog {Minilog / Microcontact} Normal, Inverse
③ Microlaterolog วัด Rxo in salt mud; influenced by mud cake
④ Proximity Log — thick mud cake, Fresh water Mud
⑤ Micro-Spherically Focused Log — Microlaterolog & Proximity Log

...o-Focused Resistivity (Rxo) Logs

... to Correct for Invasion

...culate $S_{xo} = \sqrt{\frac{F R_{mf}}{R_{xo}}}$

$S_{xo} = S_w = 100\%$

HC $S_{xo} > S_w$

...rolaterolog (MLL)

Microlog วัด Rxo high $\frac{R_{xo}}{R_{mc}}$ (≥15)

...OXIMITY LOG (PL)

for Fresh Mud

for Thick Mudcake

Micro, Microlaterolog

... Invasion Deep ... Invasion ...

Rxo are influenced by Rt

...cro-Spherically Focused Log (MSFL)

Both Microlaterolog & Proximity Log

... Mud cake ...

LATEROLOG วัด Rt, Ri ใน Salt Water Base Mud

Dual Laterolog — Delaware Effect — Deeper than Laterolog 3

LLd, LLs

Rt, Ri

Laterolog ... Induction วัด Ri short normal

Laterolog 8

Spherically Focused Log — SFL — Replace short normal or Laterolog 8

- วัด Rxo high Invaded
- วัด Ri Low

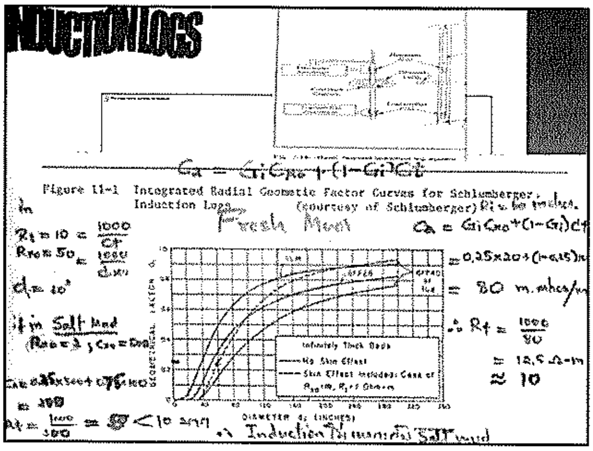
10–14 inches

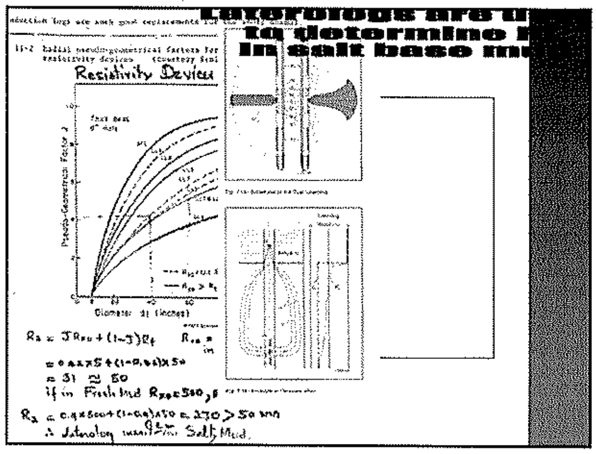
Micro-Resistivity Log — Pad Type Device

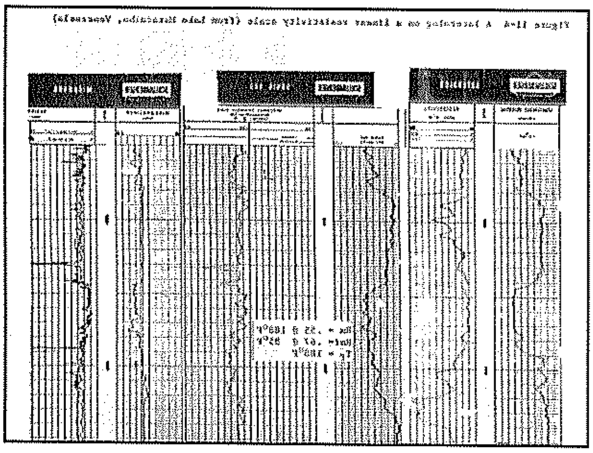
วัด Rxo, Rmc < 5 inches. $R_m < R_{mc} < R_{xo}$

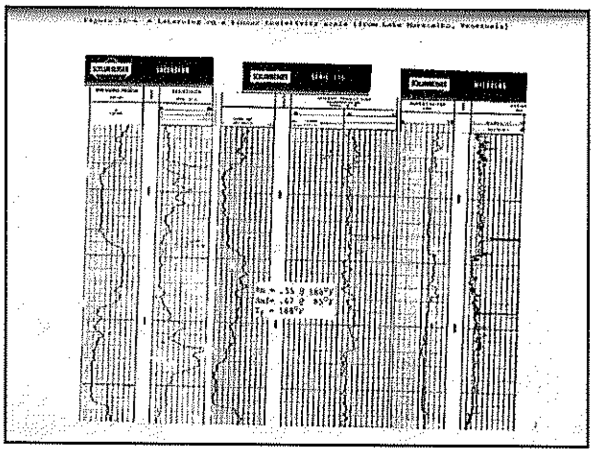
① Microlog วัด 3–4 inches, วัด Rmc — Normal, Inverse — $\frac{R_{xo}}{R_{mc}} < 15$

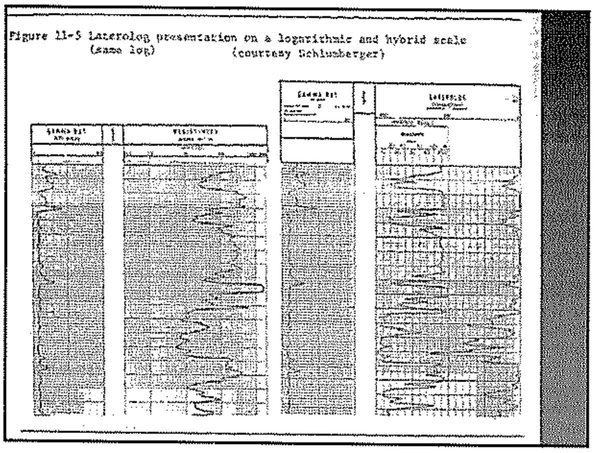
② Micro-Focused Resistivity (Rxo) Logs
- used to correct other log for Invasion
- To cal. Sxo
- Microlaterolog (MLL), Proximity Log (PL), Micro-Spherically ...











Formation Factor and Porosity

Nonshaly formation rocks 100% with brine R_w

$$F = \frac{R_o}{R_w} \quad \text{remains nearly constant}$$

Archie observation formulas

$$F = \frac{a}{\phi^m} \quad (m = \text{Cementation factor})$$

for Sands

$$F = \frac{0.62}{\phi^{2.15}} \quad \text{Humble}$$

Unconsolidated S

Compacted formation for Carbonates

$$F = \frac{1}{\phi^2} \quad \text{Chalky rocks}$$

Shaly Sand.

Humble formula Consolidated S

$$F = \frac{0.81}{\phi^2} \quad \text{Sucrosic rocks (Equi-granular)}$$

Compact:

or Oolicastic Rocks $F = \frac{1}{\phi^{2.2}} \to \frac{1}{\phi^{2.5}}$

FORMATION FACTOR & PO

$$F = \frac{R_o}{R_w} = \frac{a}{\phi^m}$$

$$F = \frac{0.62}{\phi^{2.15}}, \quad F = \frac{0.81}{\phi^2} \quad \text{For Sand - Hum}$$

$$F = \frac{1}{\phi^2} \quad \text{for Compacted form}$$

Archie

WATER SATURATION

$$S_w^n = \frac{F R_w}{R_t} \quad \text{Clean formation}$$

$$S_w = \sqrt{\frac{F R_w}{R_t}}\,; \quad n = 2$$

$$S_w = \sqrt{\frac{R_o}{R_t}} \quad \text{— (1)}$$

In Flushed Zone

$$S_{xo} = \sqrt{\frac{F R_{mf}}{R_{xo}}} \quad \text{— (2)}$$

(1)/(2) and $S_{xo} = S_w^{1/5} \Rightarrow S_w = ($

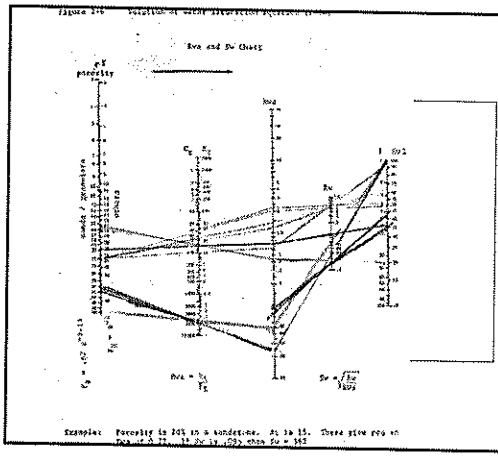
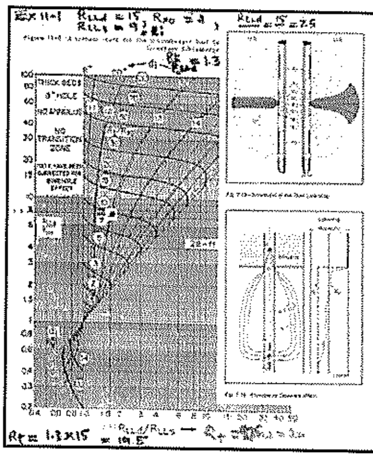


Fig 9.10 Classification of Resistivity Log

TABLE 3-1. Classification of resistivity logs

Flushed Zone (R_{xo})	Invaded Zone (R_i)	Uninvaded Zone (R_t)
Microlog	Short Normal	Long Normal
Microlaterolog	Laterolog-8 (LL8)	Laterolog
Proximity Log	Spherically Focused Log (SFL)	Deep Induction Log
Microspherically Focused Log (MSFL)	Medium Induction	Deep Laterolog (LLD)
	Shallow Laterolog (LLS)	Laterolog-3 (LL3)
		Laterolog-7 (LL7)
		Induction Log (6FF40)



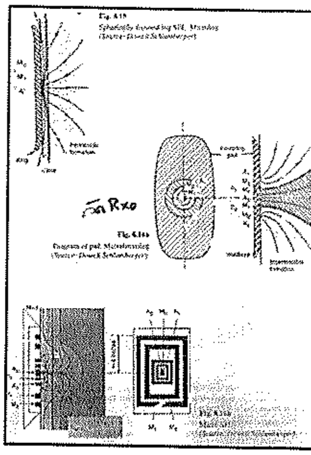
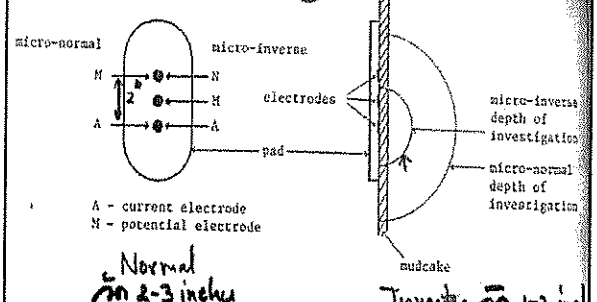


Figure 11-11 Schematic of Microlog pad and electrodes

Microlog วัด R_{xo}, R_c



Normal วัด 2-3 inches

Inverse วัด 1-2 inch

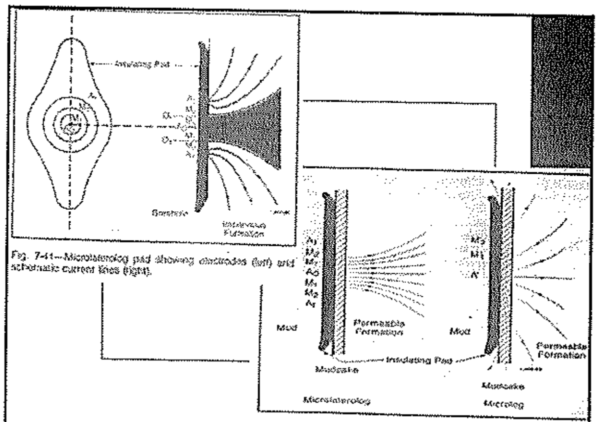
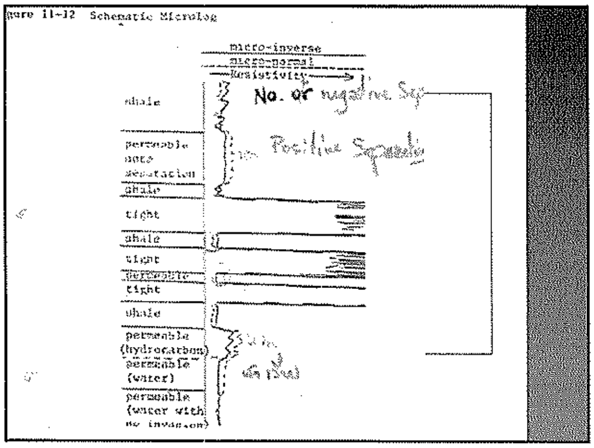


Fig. 7-41—Microlaterolog pad showing electrodes (left) and schematic current lines (right).

Fig. 7-42—Comparative distribution of current lines of Microlaterolog and Microlog.


gure 11-12 Schematic Microlog
micro-inverse
micro-normal
Resistivity
No. or negative Sep
Positive Separation
shale
permeable
tight
permeable (hydrocarbon)
permeable (water)
permeable (water with no invasion)

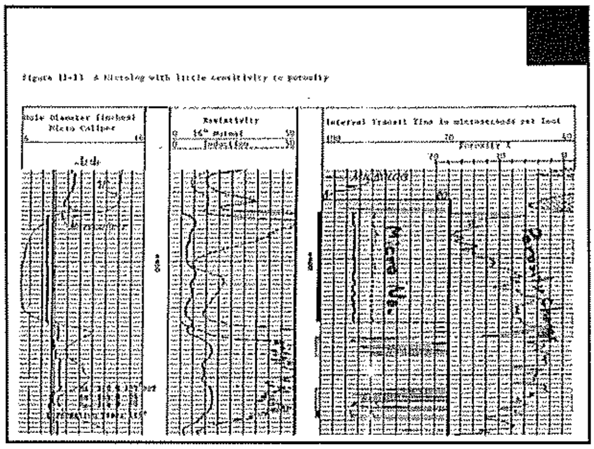
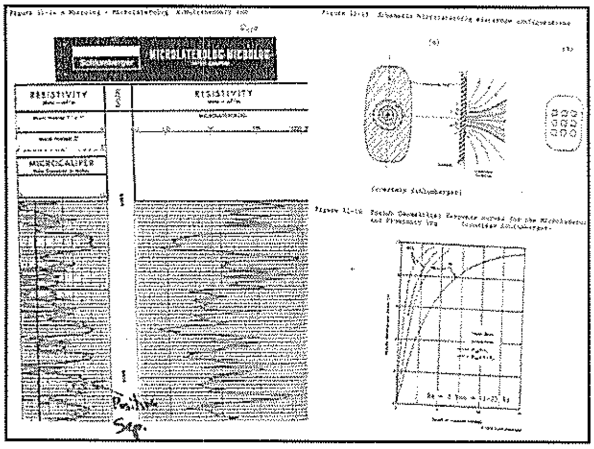
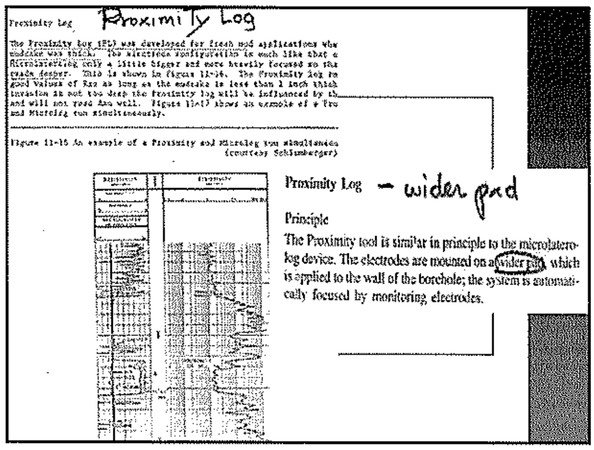
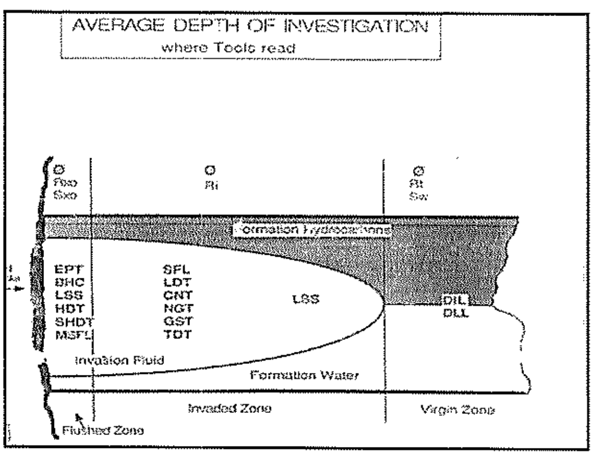
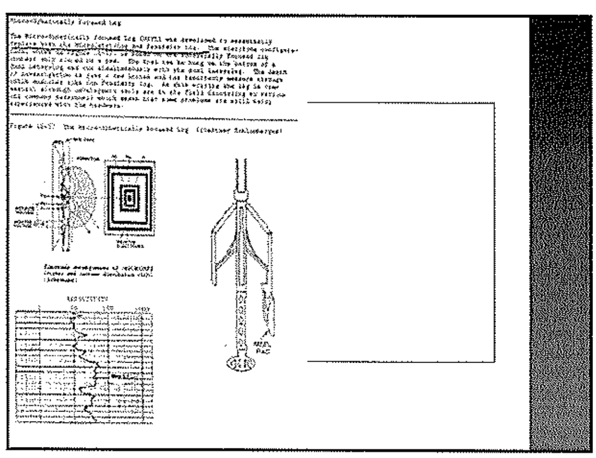


Figure 11-13 A Microlog with little sensitivity to porosity


MICROLATEROLOG MICROLOG
RESISTIVITY
MICROCALIPER
Positive Sep.


Proximity Log
ProximiTy Log
Figure 11-15 An example of a Proximity and Microlog run simultaneously
(courtesy Schlumberger)
Proximity Log – wider pad
Principle
The Proximity tool is similar in principle to the microlaterolog device. The electrodes are mounted on a wider pad, which is applied to the wall of the borehole; the system is automatically focused by monitoring electrodes.


AVERAGE DEPTH OF INVESTIGATION
where Tools read
Rxo
Sxo
Ri
Rt
Sw
Formation Hydrocarbons
EPT
BHC
LSS
HDT
SHDT
MSFL
SFL
LDT
CNT
NGT
GST
TDT
LSS
DIL
DLL
Invasion Fluid
Formation Water
Invaded Zone
Virgin Zone
Flushed Zone



CHAPTER12

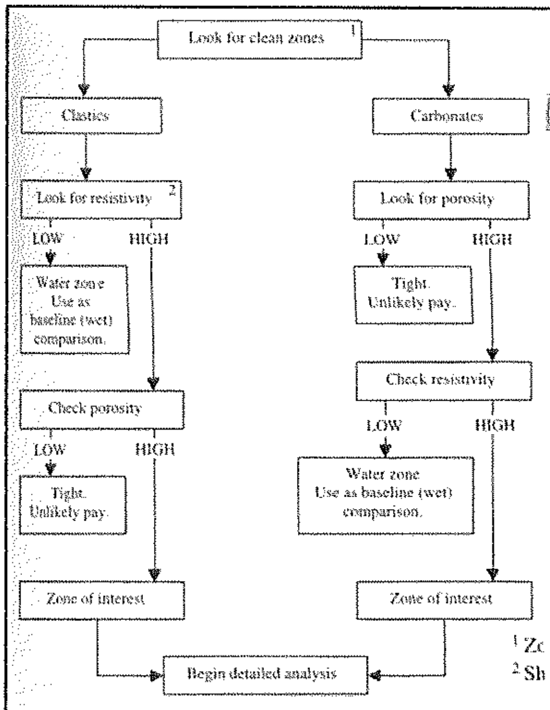
QUICK LOOK INTERPRETATIONS

INTERPRETATION

$$Q = KA(P_1 - P_2) / \mu L$$

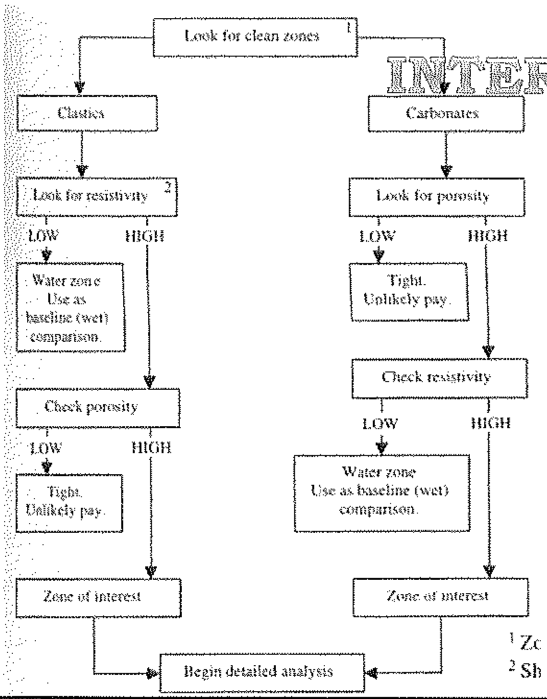
The primary goal of well log interpretation is to determine whether there is petroleum, and if so, how much can be recovered and how fast it will flow.

Well log interpretation is used to determine the economic viability of the well: How profitable it will be and how soon the drilling costs can be recovered.



TION

- Unless the stratigraphy and reservoirs are well known, the first step is to scan the well log for likely reservoirs.
- The well site geologist will have information about the location of petroleum shows



INTERPRETATION

- Which logs would be used for each of these steps? What would you look for in those logs?

Wellsite Quick look Interpretation

จุดประสงค์

1. หา HC, ชนิด
2. Pay Zone Thickness
3. ปริมาณ ϕ
4. " S_w
5. Check for Testing หา Zone ทดสอบ

Assume

1. $R_{deep} = R_t$
2. $R_{micro} = R_{xo}$
3. Moderate Invasion
4. Clean formation
5. Permeable
6. R_w Constant
7. Good Hole Condition

ch.12 QUANTITATIVE ANALYSIS PII

Quick Look Techniques

1; R_{xo}/R_t Method

Overlay curve on SP

$$SP = -K \log \frac{R_{mf}}{R_w}$$

SP ต่ำกว่า $\frac{R_{xo}}{R_t}$ น้อยกว่า 1 เป็น Hydro.C

if $S_w = 100\%$, $R_{xo} = F_R \cdot R_{mf}$ and $R_o = F_R R_w$

$$\therefore SP = -K \log \frac{R_{xo}}{R_o}$$

$R_o = R_t$ in $S_w = 100$

R_{xo} อ่านได้จาก LL8, SFL, Micro

ระวัง SP suppression จาก H.C + Shaliness

2; F & R_o log, F & R_t log.

ต้องรู้ F_{sv} curve จาก Sonic, ϕ_d, ϕ_N

$R_o = F_{sv} R_w \Rightarrow \log R_w = \log R_o - \log F_{sv}$ index

$R_t = F_R R_{wa} \Rightarrow \log R_{wa} = \log R_t - \log F_R$

Shift F overlay R_o ใน Water Zone

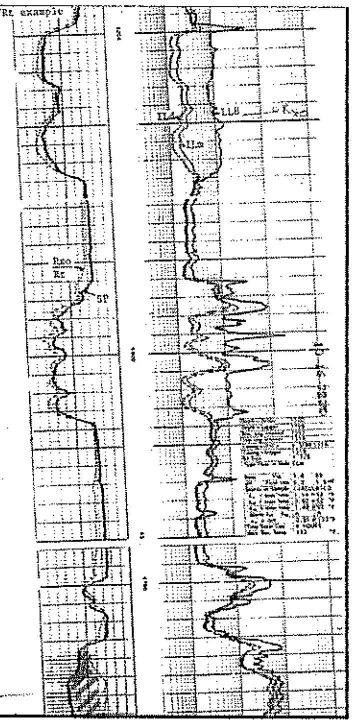
$S_w^2 = \frac{R_o}{R_t} \Rightarrow 2 \log S_w = \log R_o - \log R_t$ index

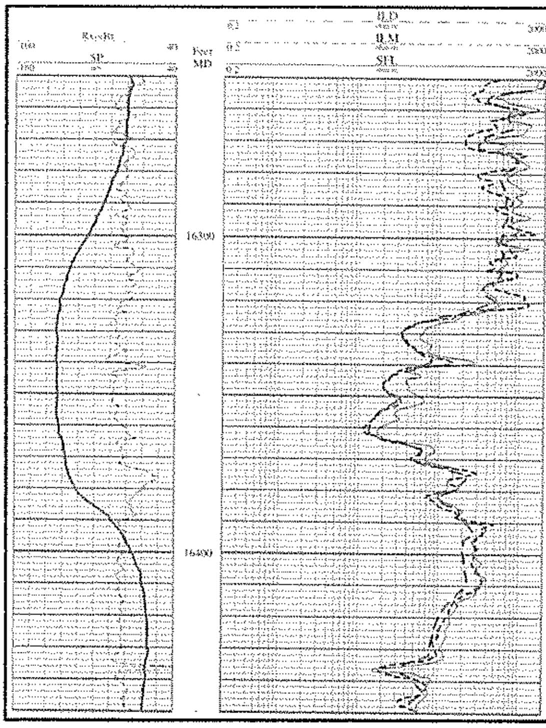
$\left(S_w^2 = \frac{F R_w}{R_t}\right)$

$$C = A - B \propto \frac{R_t}{F}$$

if $A < B$: $\frac{R_t}{F} < 1$; $A > B$: $\frac{R_t}{F} > 1$

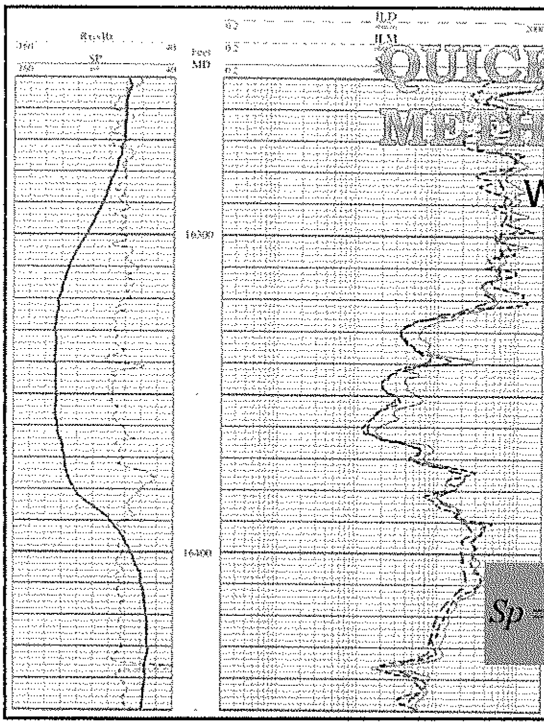
Figure 12-1a Rxo/Rt example





QUICK-LOOK METHODS: RXO/RT

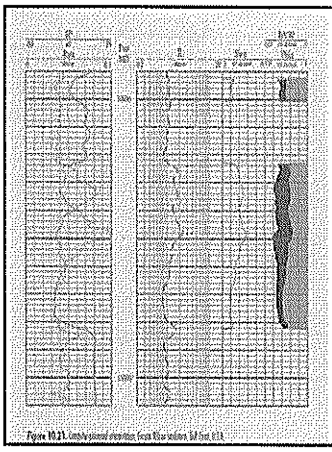
One of the reconnaissance methods is the relationship between the SP curve and the resistivity ratio R_{xo}/R_t



QUICK-LOOK METHODS: RXO/RT

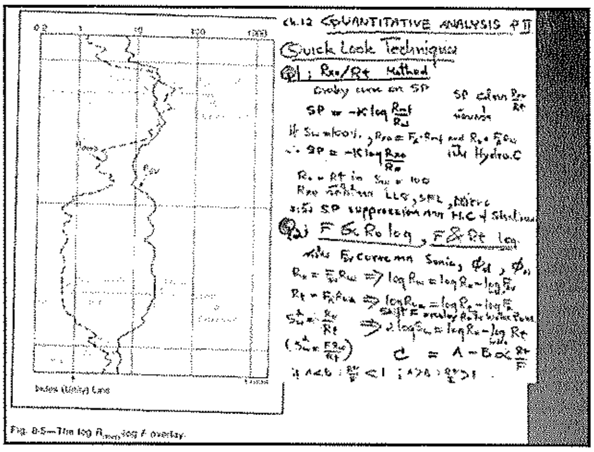
When the rock contains only water, Rxo/Rt will differ from the SP only by a constant. If petroleum is present, Rt increases so the two curves deflect away from each other.

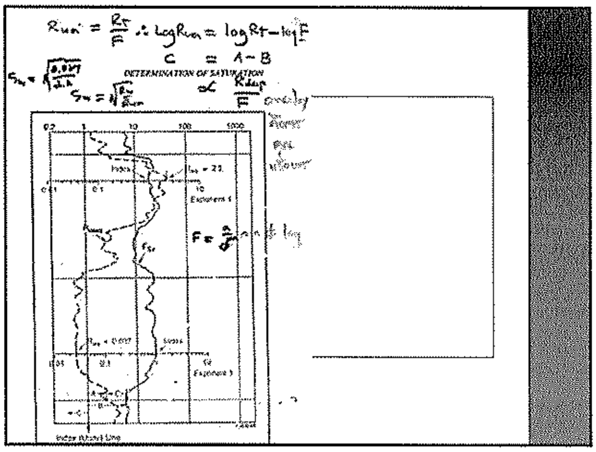
$$Sp = -K * \log\frac{R_{mf}}{R_w} \approx -K * \log\frac{R_{xo}}{R_t}$$

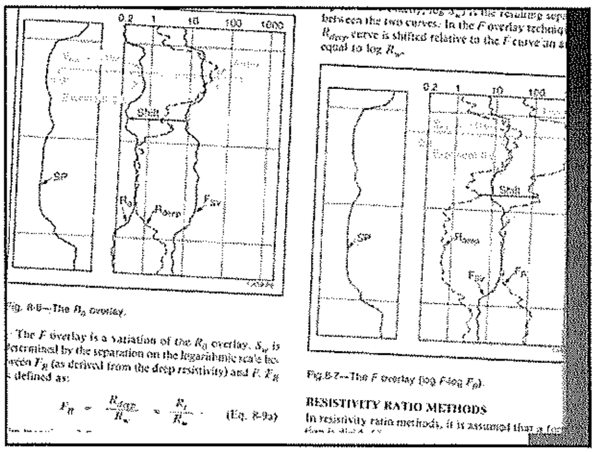


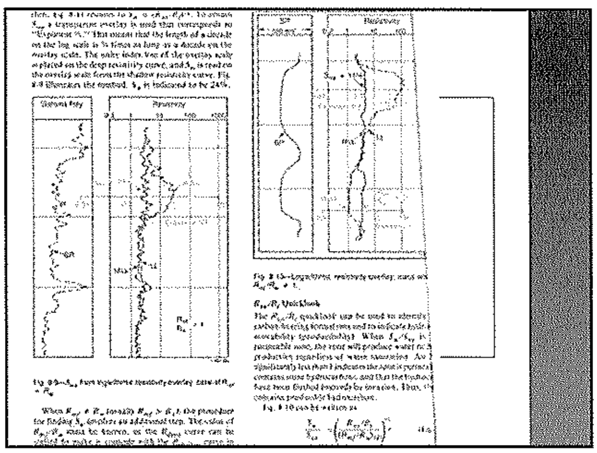
QUICK-LOOK METHODS: RWA

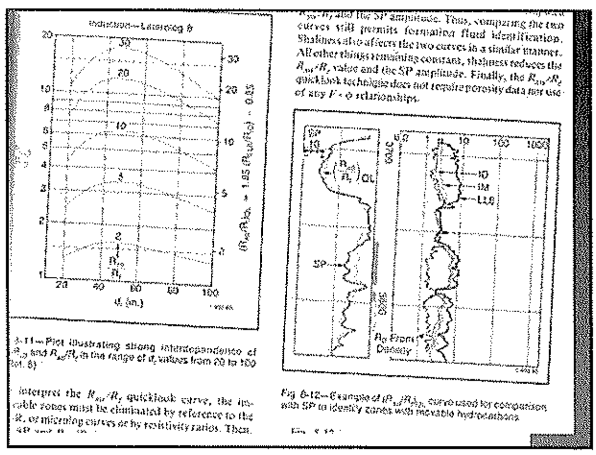
Apparent Water Resistivity (Rwa) compares the deep resistivity of various zones in the well bore. The lowest Rwa is assumed to be water, so high Rwa must contain petroleum.











Q3 R_{wa} Computation

$R_{wa} = \frac{R_t}{F_R}$ ($F_R = \frac{0.81}{\phi^2}$ SS) ($F_R = \frac{1}{\phi^2}$ L.S)

S_w 100% $R_{wa} = R_w$

$S_w = \sqrt{\frac{R_w}{R_{wa}}}$ ∴ $R_{wa} > 3 R_w$ H.C

$S_w \le \sqrt{\frac{1}{3}} \le 60\%$

Q4. F Movable Oil Plot

$F_{mp} = \frac{R_t}{R_w} = \frac{F}{S_w^2}$ ∴ $S_w = \sqrt{\frac{F_R}{F_{mp}}}$

$F_{xo} = \frac{R_{xo}}{R_{mf}} = \frac{F}{S_{xo}^2}$ ∴ $S_{xo} = \sqrt{\frac{F}{F_{xo}}}$

F_R ϕ_s, ϕ_D, ϕ_N

Q5 R_{mfa} Computation

$R_{mfa} = \frac{R_{xo}}{F_R}$ $R_{xo} < HC$

water Zone $R_{mfa} \simeq R_{mf}$

HC $R_{mfa} > 1.5 R_{mf}$

Q6 POROSITY & CROSSPLOT

$\phi_s \downarrow, \phi_D \uparrow, \phi_N \uparrow$

Q7 FLUSHED ZONE METHOD

$\left(\frac{S_w}{S_{xo}}\right)^2 = \frac{R_{xo}/R_t}{R_{mf}/R_w}$

$S_w = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{5/8}$

Q8 Invaded Zone Method

$S_i^2 = \frac{F R_z}{R_t}$; $S_i = S_w^{1/2}$

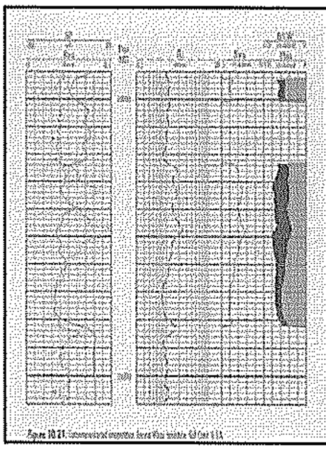
$S_w = \frac{R_i/R_t}{R_z/R_w} = \frac{10/20}{0.27/0.05}$

$\frac{1}{R_z} = \frac{z}{R_w} + \frac{1-z}{R_{mf}}$

$z = 0.075$ normal $\rightarrow$ 0.035 deep

$\frac{1}{R_z} = \frac{0.035}{0.02} + \frac{1-0.035}{0.5}$

$\frac{1}{R_z} = 3.68 \Rightarrow R_z = 0.27$



QUICK-LOOK METHODS: RWA

This works because

$$R_o = F * R_w$$

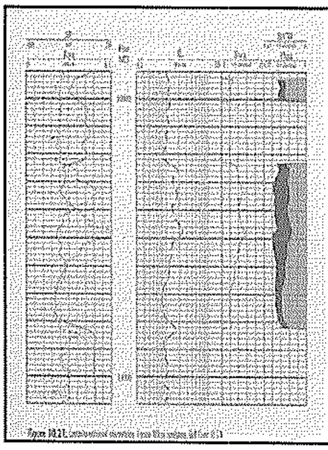
or

$$R_w = \frac{R_o * \Phi^m}{a}$$

and

$$R_{wa} = \frac{R_t * \Phi^m}{a}$$

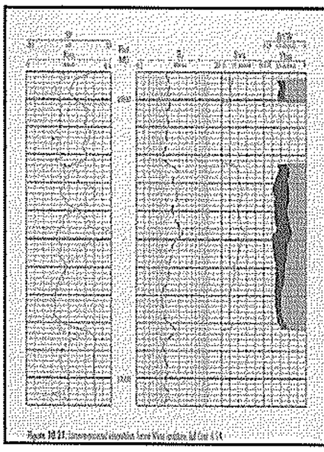
Need info about lithology and porosity



QUICK-LOOK METHODS: RWA

If the lowest Rwa reading reflects only water in the pores, then the apparent water saturation (Swa) can be estimated by:

$$S_{wa} = \sqrt{\frac{R_{wamin}}{R_{wazone}}}$$



QUICK-LOOK METHODS: RWA

This Swa assumes that the zones being compared have the same lithology and porosity.

$$S_{wa} = \sqrt{\frac{R_{wamin}}{R_{wazone}}}$$

QUICK-LOOK METHODS: RESISTIVITY POROSITY

This method calculates a porosity from resistivity data using the Archie Equation, and assuming Sw = 1

In zones that are water filled, Φ is high and equal to the true porosity.

In zones that have petroleum, Rt is high and Φ is lower than the true value.

Φ_R is plotted with porosity logs and knowledge of the lithology is assumed.

$$S_w = \left(\frac{a * R_w}{R_t * \Phi^m}\right)^{\frac{1}{n}}$$

or

$$\Phi_R = \left(\frac{a * R_w}{R_t * S_w^n}\right)^{\frac{1}{m}}$$

When $S_w = 1$,

$$\Phi_R = \left(\frac{a * R_w}{R_t}\right)^{\frac{1}{m}}$$

QUICK-LOOK METHODS: WET RESISTIVITY (RO)

Ro is the actual resistivity of the formation and fluids. Rt is the measured value.

Ro can be estimated from the formation factor (a, m & Φ), and Rw.

Assuming a value for Rw and Φ, then Ro is the estimate for the resistivity of a water saturated zone.

$$R_0 = \frac{a * R_w}{\Phi^m}$$

QUICK-LOOK METHODS: WET RESISTIVITY (RO)

When the calculated Ro is plotted with Rt, the deep measurement by the log, the two traces should overlay if there is no petroleum. Otherwise, the two curves will diverge.

$$R_0 = \frac{a * R_w}{\Phi^m}$$

Q4. F Movable Oil Plot

$$F_{deep} = \frac{R_t}{R_w} = \frac{F}{S_w^2} \therefore S_w = \sqrt{\frac{F_r}{F_{deep}}}$$

$$F_{xo} = \frac{R_{xo}}{R_{mf}} = \frac{F}{S_{xo}^2} \therefore S_{xo} = \sqrt{\frac{F}{F_{xo}}}$$

F_w = Fr drawn on ϕ_s, ϕ_D, ϕ_N $F_r = \frac{1}{\phi^2}$ $F_r = 0.62$

Q5 Rmfa Computation

$$R_{mfa} = \frac{R_{xo}}{F_{xo}}$$

Water Zone $R_{mfa} \approx R_{mf}$

HC $R_{mfa} > 1.5 R_{mf}$

---

arying amounts of shaliness. The productive gas sand is lentified by the separation between the R_{xo}/R_t and SP urves. Water-productive zones are shown by lack of eparation. In shaly water zones the variation in the SP urve is essentially the same as the variation in the R_{xo}/R_t atio — a result of the same shale; so, the comparison is ot significantly disturbed by shaliness. Neither is it listurbed by variations in R_w.

Estimates of water saturation and saturation ratio in lean formations can be made by comparing the R_{xo}/R_t and SP curves. Eq. 8-17 permits S_w/S_{xo} to be estimated and Eq. 8-11 (assuming $S_{xo} = S_w^{1/5}$) permits S_w to be stimated.

F-MOP MOVABLE OIL PLOT

The F-MOP plot uses two resistivity curves and a porosity curve recorded on logarithmic scale to show hydrocarbon saturation and movability. The recorded curves are F_{deep}, F_{xo}, and F (from a porosity log), where

$$F_{deep} = \frac{R_{deep}}{R_w} = FS_w^2 \qquad \text{(Eq. 8-19a)}$$

$$F_{xo} = \frac{R_{xo}}{R_{mf}} = FS_{xo}^2 \qquad \text{(Eq. 8-19b)}$$

and

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

On a logarithmic scale, the apparent formation factor curves, F_{deep} and F_{xo}, are located by shifting the corresponding resistivity curve by log R_w or log R_{mf} ...

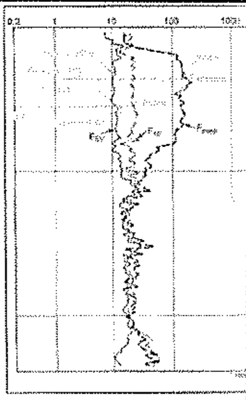
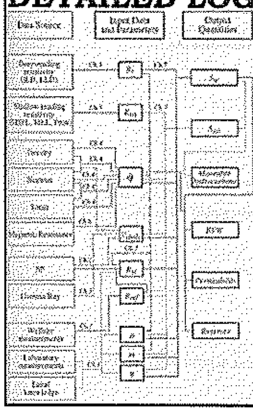


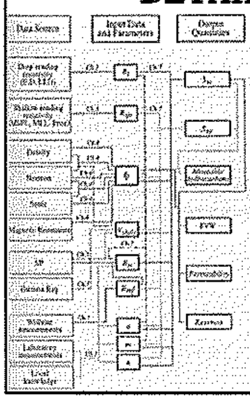
Fig. 8-13—The F-MOP.

DETAILED LOG ANALYSIS



Once prospective hydrocarbon zones have been identified, then calculations of the desired parameters for economic evaluation are made.

DETAILED LOG ANALYSIS: WATER SATURATION



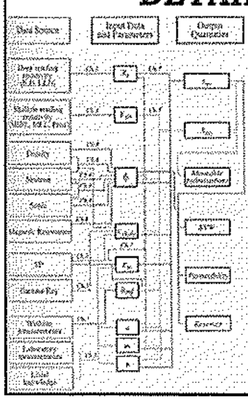
Water saturation in the flushed zone and the uninvaded zone are calculated using the Archie Equation.

$$S_w = \left(\frac{a * R_w}{R_t * \Phi^m}\right)^{\frac{1}{n}}$$

and

$$S_{xo} = \left(\frac{a * R_{mf}}{R_{xo} * \Phi^m}\right)^{\frac{1}{n}}$$

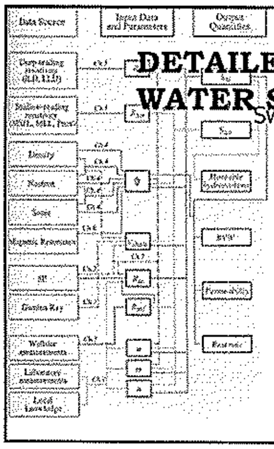
DETAILED LOG ANALYSIS: WATER SATURATION



Instead of calculating Sw and Sxo separately, it is useful to calculate their ratio, because the lithology factors are eliminated.

$$\left(\frac{S_w}{S_{xo}}\right)^n = \frac{R_{xo}/R_t}{R_{mf}/R_w}$$

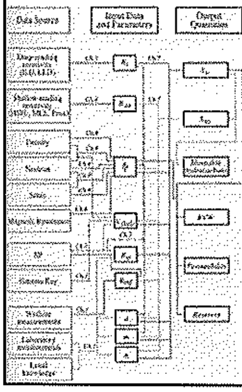
DETAILED LOG ANALYSIS: WATER SATURATION



Sw/Sxo is the *Moveable Hydrocarbon Index.* If Sw/Sxo = 1, no hydrocarbons were moved. If it is less than 0.7 for ss, or less then 0.6 for carbs, then petroleum will move.

$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{\frac{1}{2}}$$

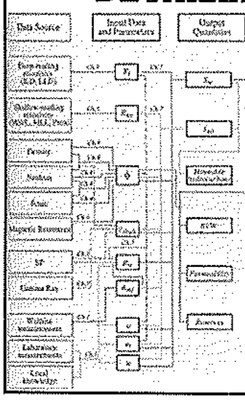
DETAILED LOG ANALYSIS: R SATURATION



$$S_w = \left(\frac{a * R_w}{R_t * \Phi^m}\right)^{\frac{1}{n}}$$

Instead of calculating Sw using the Archie equation where lithology parameters must be known, water saturation can also be estimated using the ratio method without knowing the lithology parameters.

DETAILED LOG ANALYSIS: ATURATION

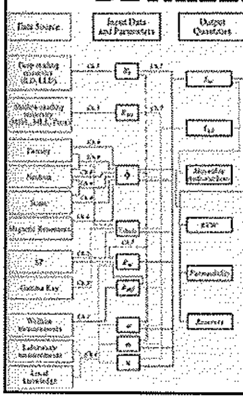


$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{\frac{1}{2}}$$

The saturation ratio can be determined using only resistivity data (above). If petroleum is present, then:

$$S_{xo} \approx (S_w)^{\frac{1}{5}}$$

DETAILED LOG ANALYSIS: ATURATION

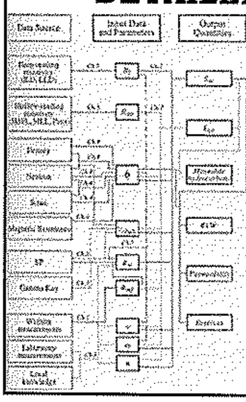


$$\frac{S_w}{S_{xo}} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{\frac{1}{2}} \qquad S_{xo} \approx (S_w)^{\frac{1}{5}}$$

Substituting Sxo gives Swr (water saturation ratio method).

$$S_{wr} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{\frac{5}{8}}$$

DETAILED LOG ANALYSIS: ATURATION



Swr can be used as a check on Sw computed using the Archie equation

$$S_{wr} = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{\frac{5}{8}} \qquad S_w = \left(\frac{a * R_w}{R_t * \Phi^m}\right)^{\frac{1}{n}}$$

DETAILED LOG ANALYSIS: IRREDUCIBLE WATER SATURATION

Water saturation, Sw, includes water that is bound to particle surfaces, and water that will not move because of capillary pressure. This is called *irreducible water saturation,* S_{wirr}.

If Sw = Swirr, then no water will be produced, which is important to know in making an economic evaluation of the well.

DETAILED LOG ANALYSIS: BULK VOLUME WATER

Table 7.1. Bulk volume water (BVW) as a function of grain size and type of carbonate rock.

Lithology	Grain Size (millimeters)	Bulk Volume Water (BVW)
Clastics		
Coarse	1.0 to 0.5	0.02 to 0.025
Medium	0.5 to 0.25	0.025 to 0.035
Fine	0.25 to 0.125	0.035 to 0.05
Very Fine	0.125 to 0.062	0.05 to 0.07
Silt	< 0.062	0.07 to 0.09
Carbonates		
Vuggy		0.005 to 0.015
Vuggy and intercrystalline (intergranular)		0.015 to 0.025
Intercrystalline		0.025 to 0.04
Chalky		0.05

The bulk volume water values for carbonates should be used only as a very general guide to different types of porosity.

Bulk water volume (BVW) = $S_w * \Phi$.

Table 7.1 shows estimates of BWV at irreducible water saturations, so calculation of BVW can show whether the reservoir will produce water along with petroleum

DETAILED LOG ANALYSIS: BULK VOLUME WATER

Buckles plots are a way of determining whether the reservoir is at Swirr. (The ordinate should be Sw, not Swirr).

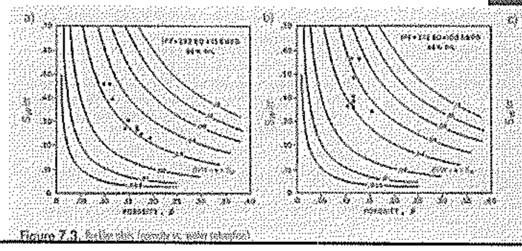


Figure 7.3. Buckles plot (porosity vs. water saturation)

DETAILED LOG ANALYSIS: BULK VOLUME WATER

Plots of Φ against Sw will follow the hyperbolic curves of BVW if the reservoir is at Swirr (left). Otherwise, both petroleum & water production are likely.

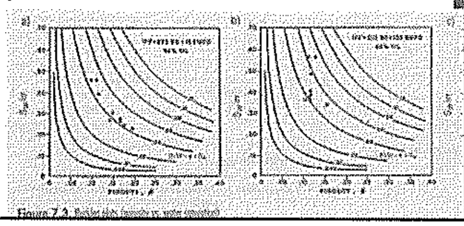


Figure 7.3. Buckles plot (porosity vs. water saturation)

DETAILED LOG ANALYSIS: ASSIGNMENT

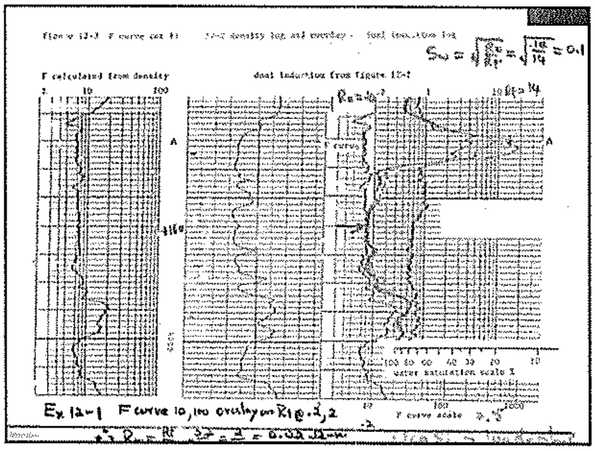
On your spreadsheet from the previous resistivity assignment, add columns to calculate water saturation using the ratio method (Swr), Moveable Hydrocarbon Index (MHI), and Bulk Volume Water (BVW).

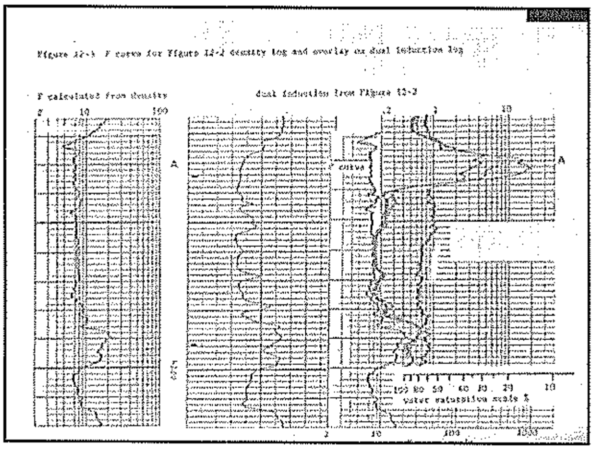
Make a Buckles plot of Sw and Φ to determine whether the zones are at Swirr.

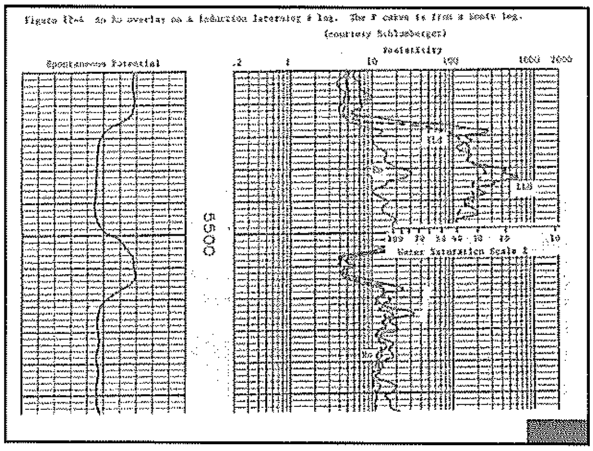
For each of the zones you have analyzed, describe and explain the potential to recover hydrocarbons economically.

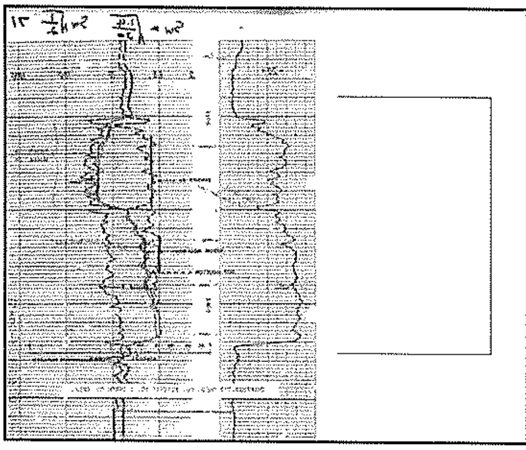
DETAILED LOG ANALYSIS: SATURATION CROSSPLOTS

With the advent of computers, graphical solutions to the Archie equation aren't so necessary any more. However, there are two that are sometimes used to get a visual picture of the productive zone saturation.









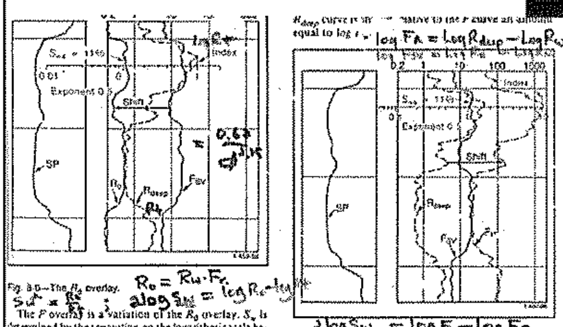


Fig. 8-6—The R_o overlay.

$R_o = R_w \cdot F_r$

$S_w^2 = \frac{R_o}{R_t}$; $2 \log S_w = \log R_o - \log R_t$

The F overlay is a variation of the R_o overlay. S_w is determined by the separation on the logarithmic scale between F_R (as derived from the deep resistivity) and F. F_R is defined as:

$\log S_w = \frac{1}{2}\log F_r - \frac{1}{2}\log F_R$

$$F_R = \frac{R_{deep}}{R_w} = \frac{F_t}{R_w} \quad \text{(Eq. 8-9a)}$$

The meaning of F_R in terms of S_w is seen by replacing

$2 \log S_w = \log F_r - \log F_R$

Fig 8-7—The F overlay (log F-log F_R).

RESISTIVITY RATIO METHODS

In resistivity ratio methods, it is assumed that a formation is divided into two distinct regions, a flushed or invaded zone and a noninvaded zone. Both zones have the

varying amounts of shaliness. The productive ... sand is identified by the separation between the $F_{...}$ ... SP curves. Water-productive zones are shown by lack of separation. In shaly water zones the variation in the SP curve is essentially the same as the variation in the R_{xo}/R_t ratio — a result of the same shale; so, the comparison is not significantly disturbed by shaliness. Neither is it disturbed by variations in R_w.

Estimates of water saturation and saturation ratio in clean formations can be made by comparing the R_{xo}/R_t and SP curves. Eq. 8-17 permits S_w/S_{xo} to be estimated and Eq. 8-11 (assuming $S_{xo} = S_w^{1/5}$) permits S_w to be estimated.

F-MOP MOVABLE OIL PLOT

The F-MOP plot uses two resistivity curves and a porosity curve recorded on logarithmic scale to show hydrocarbon saturation and movability. The recorded curves are F_{deep}, F_{xo}, and F (from a porosity log), where

$$F_{deep} = \frac{R_{deep}}{R_w} = FS_w^2 , \quad \text{(Eq. 8-19a)}$$

$$F_{xo} = \frac{R_{xo}}{R_{mf}} = FS_{xo}^2 , \quad \text{(Eq. 8-19b)}$$

and

$$F = \frac{a}{\phi^m} = F_{SV}$$

On a logarithmic scale, the apparent formation factor curves, F_{deep} and F_{xo}, are located by shifting the corresponding resistivity curve by log R_w or log R_{mf}, whichever is appropriate. The F curve is a log ϕ curve recorded at the proper sensitivity and polarity.

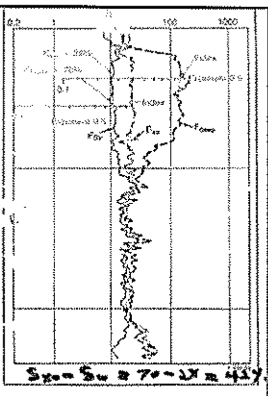


Fig. 8-13—The F-MOP.

method is used where gas saturation is the primary infor-

HINGLE CROSSPLOT

RPC (Resistivity Porosity Crossplots)

1. Read Resistivity & ϕ_N, ϕ_D, ϕ_S
2. เลือก Graph Fig 12-5 or 12-6
3. Plot R — ϕ บน Graph ... crossplot
4. Water Zone ... Matrix Value ... ϕ
5. Lay out the porosity Scale. (or shift)
6. Slope ของเส้น ... Rw ... ϕ ... F ... Ro ... Rw ... agree กับ SP ... Slope
7. Zone ... Sw < 100% ... (Ro) ... Move Sw Scale ... Ro & Sw ... origin (Matrix pt.) ... Sw = 10, 20 30, 40 ... %
8. ... water Sw ... plot.

HINGLE CROSSPLOT

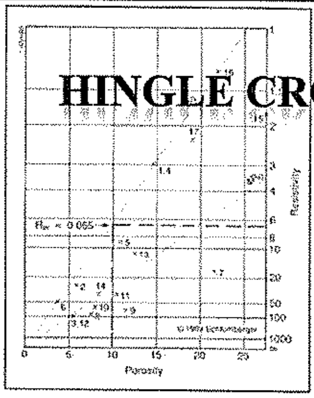
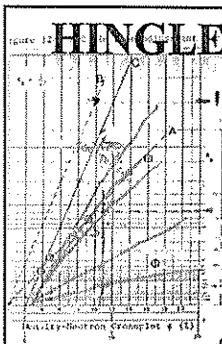


Fig. 8-1—Resistivity-porosity crossplot for determining R_w and S_w.

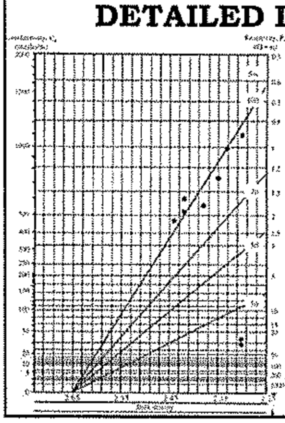
HINGLE CROSSPLOT



$\phi = 10\%$

2. Graph Fig 12-5 or 12-6
3. Plot R — ϕ Graph crossplot
4. Water Zone ... Matrix ... ϕ
5. Lay out the porosity Scale.
6. Slope ... Rw ... ϕ ... F ... Ro ... Rw ... agree ... SP ... o.k. ... Slope.
7. ... Sw < 100% ... Have Sw Scale ... origin (Matrix pt.) ... Sw ...
8. ... Sw ... plot.

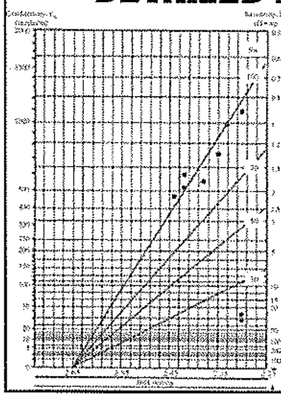
DETAILED LOG ANALYSIS: HINGLE CROSSPLOT



Hingle crossplots are strange and based on this form of the Archie equation:

$$\left(\frac{a}{R_t}\right)^{\frac{1}{m}} = \left(\frac{S_w^n}{R_w}\right)^{1/m} * \Phi$$

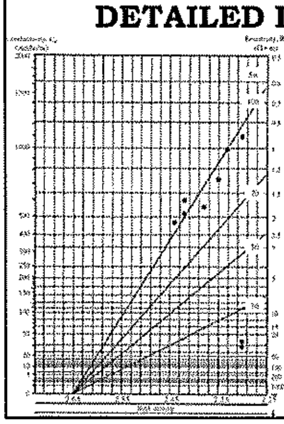
DETAILED LOG ANALYSIS: HINGLE CROSSPLOT



Φ, or any proxy such as the density or sonic logs is plotted on a linear scale at the bottom. The ordinate is $1/R_t$ (or conductivity) and has to be scaled for particular values of "a" and "m".

$$\left(\frac{a}{R_t}\right)^{\frac{1}{m}} = \left(\frac{S_w^n}{R_w}\right)^{1/m} * \Phi$$

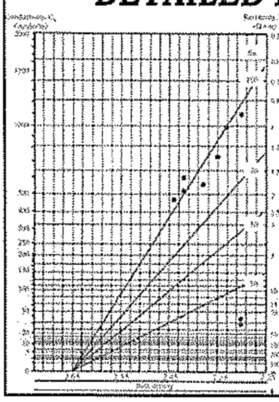
DETAILED LOG ANALYSIS: HINGLE CROSSPLOT



The scaling of the ordinate must be designed so that values of Rt and Φ plot as a straight line for constant Sw.

$$\left(\frac{a}{R_t}\right)^{\frac{1}{m}} = \left(\frac{S_w^n}{R_w}\right)^{1/m} * \Phi$$

DETAILED LOG ANALYSIS: HINGLE CROSSPLOT



While "a" and "m" must be assumed to design a Hingle plot to get a straight line, the data plotted on the Sw=1 line can be used to calculate Rw. Sw<1 can also be estimated once the Sw=1 line is established.

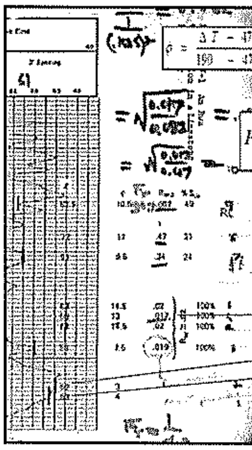
$$\left(\frac{a}{R_t}\right)^{\frac{1}{m}} = \left(\frac{S_w^n}{R_w}\right)^{1/m} * \Phi$$

The Hingle Crossplot. The Hingle crossplotting technique is a powerful technique allowing a long section of well logs to be analyzed in a minimum of time. The advantage of Hingle plot over the Pickett plot is that a matrix value does not have to be known or assumed. It is determined from the crossplot.

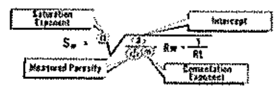
If very little is known about a formation to be analyzed, both the Pickett and Hingle crossplots can be used together. The Pickett plot gives us m and the Hingle plot gives us the matrix value and R_w. However, the Hingle plot requires a special graph paper. Figures 3–57 and 3–58 show two graph papers for $F_R = 0.62/\phi^{2.15}$ (sandstone) and $F_R = 1/\phi^2$ (carbonates) respectively.

The following steps will help in constructing the Hingle plot and determine S_w, R_w, and appropriate matrix value:

1. Select the appropriate graph paper. A special graph paper could be constructed if a and m are different than those in Figures 3–57 and 3–58.
2. Scale the x-axis on a linear scale, using Δt_{log}, ρ_b, ϕ_N, ϕ_{ND} or ϕ_{ND}.
3. Plot deep resistivity values on y-axis corresponding to the respective porosity values. The resistivity and conductivity scale may be changed to facilitate plotting of any particular set of data. The scale can be changed by dividing or multiplying it by a constant.
4. Construct a straight line through the most northwesterly points, and extrapolate the line to infinite resistivity ($R_t = \infty$). This line represents the R_o line or the $S_w = 100\%$ line.
5. The intersection point of the x-axis and the R_o line represent $\phi = 0\%$ and the correct formation matrix value. The scale should then be readjusted accordingly.
6. Using the formula $R_w = R_t/F_R$ and any corresponding set of ϕ and R_t values, calculate R_w.
7. Construct the lines of constant S_w using $S_w = \sqrt{R_o/R_t}$ for any given porosity value. Note that all S_w lines will converge at the matrix point ($\phi = 0$ and $R_t = \infty$). These lines are valid only if R_w is constant throughout the interval whose resistivity and porosity values are plotted



$$\phi = \frac{\Delta T - 47.5}{189 - 47.5}$$



$$F_R = \frac{1}{\phi^2} \qquad S_w = \sqrt{\frac{R_o}{R_{wa}}} \qquad R_{wa} = \frac{R_t}{F_R}$$

Rt	del T	$\phi = \frac{\Delta T - 47.5}{189 - 47.5}$	$F_R = \frac{1}{\phi^2}$	$R_{wa} = \frac{R_t}{F_R}$	$S_w = \sqrt{\frac{R_o}{R_{wa}}}$
7.5	62.5	0.11	90.25	0.083	[illegible]
16.5	72	0.17	33.83	0.488	[illegible]
38	61	0.09	111.42	0.341	[illegible]
1	68	0.14	48.32	0.021	[illegible]
1	66	0.13	59.33	0.017	[illegible]
1	68	0.14	48.32	0.021	[illegible]
3.5	58	0.07	184.18	0.019	[illegible]
65	52	0.03	1002.78	0.065	[illegible]
80	53	0.04	671.28	0.119	[illegible]

Ex. 6.1

$\Delta t_{sh} = 120\ \mu s/ft$ in gas sand

$\Delta t = 110\ \mu s/ft$

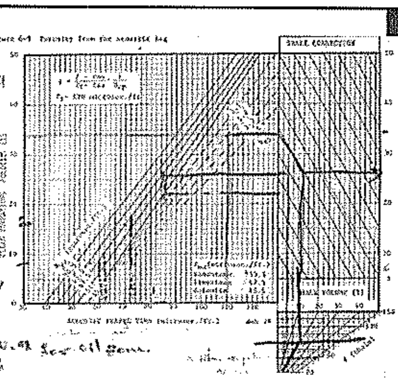
$B_{cp} = \frac{120 \times 1}{100} = 1.2$

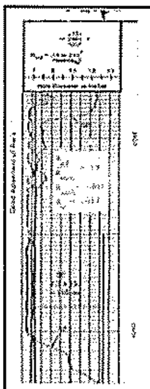
$\phi = 34\%$

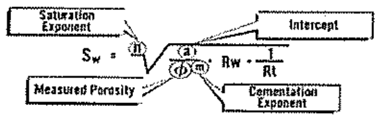
in gas

$\phi_c = 34 \times 0.7 = 24\%$

$\phi_c = 34 \times 0.9$ for oil zone. $= 30.6$







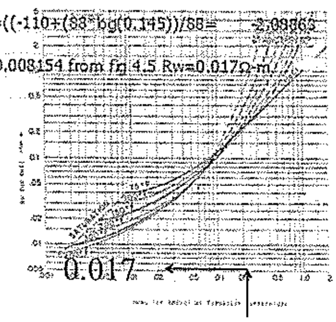
$$K = 60 + 0.133 \times T_f$$
$$= 60 + 0.133 \times 140 = 78.62$$
$$\log R_{weq} = \left[\frac{-75 + (78.62)\log(1.0)}{78.62}\right]$$
$$R_{weq} = 0.111$$

Rmf=0.36@80=0.145@210

K=60+0.133*210= 87.93

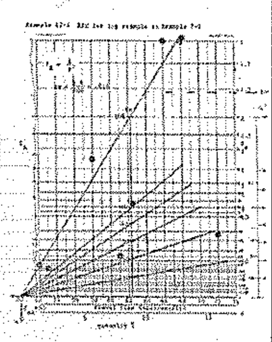
LOG(Rweq)=((-110+(88*log(0.145))/88= -2.08865

Rweq= 0.008154 from fig 4.5 Rw=0.017Ω-m



0.017

	del T	$\phi = \frac{\Delta T - 47.5}{189 - 47.5}$	$F_R = \frac{1}{\phi^2}$	$R_{wa} = \frac{R_t}{F_R}$	$S_w = \sqrt{\frac{R_o}{R_{wa}}}$
7.5	62.5	0.11	90.25	0.083	0.45
16.5	72	0.17	33.83	0.488	0.19
38	61	0.09	111.42	0.341	0.22
1	68	0.14	48.32	0.021	0.91
1	66	0.13	59.33	0.017	1.00
1	68	0.14	48.32	0.021	0.91
3.5	58	0.07	184.18	0.019	0.95
65	52	0.03	1002.75	0.065	0.51
80	53	0.04	671.28	0.119	0.38



$F = \frac{1}{(0.1)^2} = 100$

$R_o = \frac{R_T}{100}$

$R_w = \frac{6.5}{100} = 0.065$

$S_w = \sqrt{\frac{F \cdot R_w}{R_t}}$

$R_t = \frac{R_o}{S_w^2}$

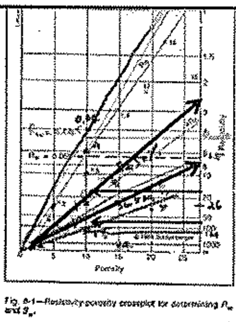


Fig. 8-1—Resistivity-porosity crossplot for determining R_w and S_w.

Fig. 8-1 shows several points plotted over an interval

$R_t = \frac{F \cdot R_w}{S_w^2} = \frac{6.5}{0.5^2} = 26$

$0.2^2 \quad R_t = 162$

SW	RT
0.6	18
0.5	26
0.4	41
0.3	72
0.2	163
0.1	650

HINGLE CROSSPLOT

TABLE 3-8 ... data for the ... in Figure 3-...

Zone	[illegible]	[illegible]	[illegible]	ϕ
1	68.8	1.00	21.3	0.15
2	68.5	1.10	21.0	0.15
3	69.5	2.10	22.0	0.16
4	61.0	4.00	13.5	0.10
5	72.3	16.5	24.8	0.16
6	62.5	7.50	15.0	0.11
7	67.8	8.30	20.3	0.14
8	60.0	8.20	12.5	0.09
9	52.0	28.0	4.50	0.03

To find the S_w for the nine zones, we construct water saturation lines for S_w = 80%, 60%, 40%, 20%, and 10% on Figure 3-56, using ϕ = 10% and R_o as given below.

ϕ	S_w	R_o	$R_t = R_o/S_w^2$
0.10	80.	2.4	3.75
0.10	60	2.4	6.67
0.10	40	2.4	15.00
0.10	20	2.4	60.00
0.10	10	2.4	240.00

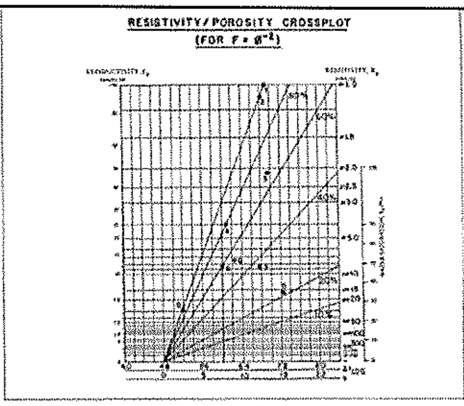


Figure 3-59. Resistivity-porosity crossplot (Hingle) for data in Table 3-8.

Figure 12-7 RPC (drawing of Ro line)

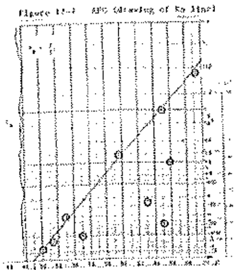


Figure 12-8 RPC (checking of Rw from Ro line)

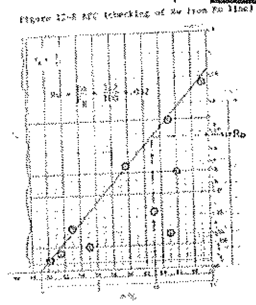
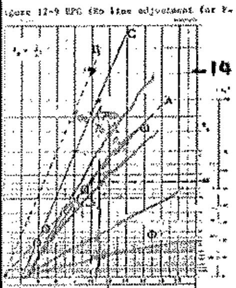


Figure 12-9 RPC (Ro line adjustment for F...

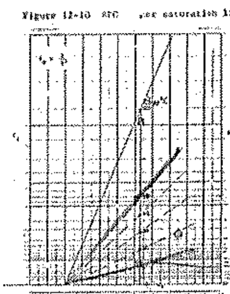


Density-Neutron Crossplot φ (%)

A line drawn first. Rw from A =.60) $\phi = .1$
B line drawn for correct Rw =.14 Ro=14)
C line = B line shifted with same slope
C is proper Ro line--porosity scale adjusted)

$@ \phi = 10\%$

Figure 12-10 RPC (... saturation lines)



porosity %

(Shift line A to B where Sw=100% touches Ro line and Sw =0% touches R = ...

$R_t = \frac{F_r \cdot R_w}{S_w^2}$

$F = \frac{1}{(0.1)^2} = 100$

$R_o = \frac{R_T}{100}$

$R_w = \frac{6.5}{100} = 0.065$

$S_w = \sqrt{\frac{F \cdot R_w}{R_t}}$

$R_t = \frac{R_o}{S_w^2}$

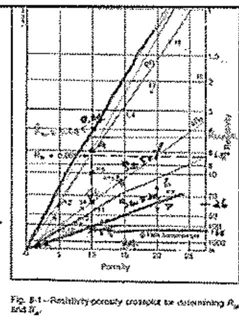


Fig. 8-1—Resistivity-porosity crossplot for determining R_w and S_w.

Fig. 8-1 shows several points plotted over an interval

$R_t = \frac{F \cdot R_w}{S_w^2} = \frac{6.5}{0.5^2} = 26$

$0.2^2 \quad R_t = 162$

Log-log Resistivity-Porosity Crossplots

Pickett plot

$R_t = \frac{F_R R_w}{S_w^n}$ Assume $F_r = \phi^{-m}$

$R_o = F_r * R_w$

$\log Rt = -m \log\phi + \log R_w - n \log S_w$

For $S_w = 100\%$

$\underbrace{\log Rt}_{y} = \underbrace{-m \log \phi}_{ax} + \underbrace{\log R_w}_{c}$

เส้น $S_w = 100\%$ เป็น R_o line

Slope $= -m$ R_o เมื่อ $\phi = 1$ จะเท่ากับ R_w

เมื่อ $\phi = 12\%$ $S_w = 100$ $R_t = 1.0$, $R_o = 1.0$

if " " Slope $= m = 2$

$S_w = 0.5$ $R_t = \frac{R_o}{S_w^2} = \frac{1}{0.5^2} = 4$

$S_w = 0.30 = \frac{1}{0.30^2} = 11$

DETAILED LOG ANALYSIS: PICKETT CROSSPLOT

The logarithmic form of the Archie equation can be written in a couple of ways:

$$S_w^n = \left(\frac{a * R_w}{\Phi^m * R_t}\right)$$

$$\log R_t = \log(a * R_w) - m \log \Phi - n \log S_w$$

$$and, if\ S_w = 1,$$

$$\log R_t = \log(a * R_w) - m \log \Phi$$

$$or$$

$$\log \Phi = \log(a * R_w)^{1/m} - \frac{1}{m} \log R_t$$

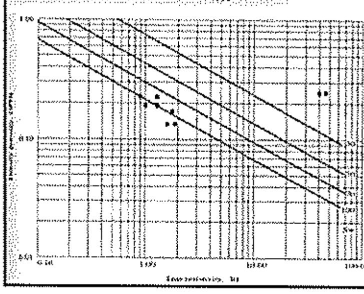
DETAILED LOG ANALYSIS: PICKETT CROSSPLOT

The form below is the one traditionally used for the Pickett crossplot. (Note equation 7.26 in text and the description in Fig. 7.4 is wrong).

$$\log \Phi = \log(a * R_w)^{1/m} - \frac{1}{m} \log R_t$$

DETAILED LOG ANALYSIS: PICKETT CROSSPLOT

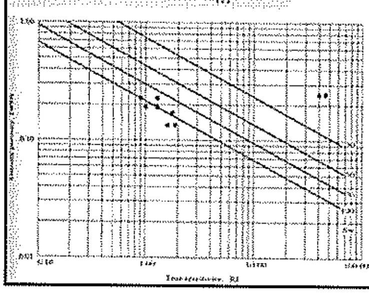
$$\log \Phi = \log(a * R_w)^{1/m} - \frac{1}{m} \log R_t$$



When Φ is plotted with R_t on log-log graph paper, the slope of the line is $-1/m$ and the intercept, when $R_t=1$, is $(a*R_w)^{1/m}$.

DETAILED LOG ANALYSIS: PICKETT CROSSPLOT

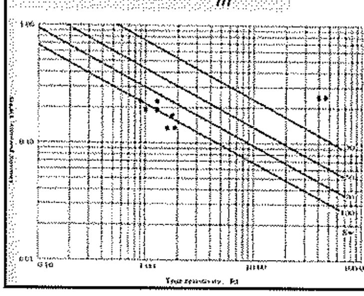
$$\log \Phi = \log(a * R_w)^{1/m} - \frac{1}{m} \log R_t$$



Note that this plot requires Sw = 1.0. If enough points can be plotted, a value of m can be determined. "a" can be calculated if Rw is known (or vice versa).

DETAILED LOG ANALYSIS: PICKETT CROSSPLOT

$$\log \Phi = \log(a * R_w)^{1/m} - \frac{1}{m} \log R_t$$

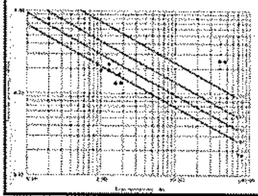


This plot also requires that the lithology ("a") and Rw be the same in all zones plotted.

DETAILED LOG ANALYSIS: [CRO]SSPLOT

Table 7.2. Factors for positioning water saturation lines on Pickett and Hingle plots

Multiplier	S_w (for n = 2.0)
1.56	0.80
2.04	0.70
2.78	0.60
4	0.50
6.25	0.40
11.11	0.30
25	0.20



$$\log \Phi = \log(a^n R_w)^{1/m} - \frac{1}{m}\log R_t$$

Lines for Sw < 1 can be drawn parallel to the Sw=1 line using the factors in table 7.2. Find Rt for Sw=1 at any arbitrary Φ, and multiply that Rt by 1.56 to get the Rt at Sw=0.8 for that Φ. Draw the line parallel to Sw=1.

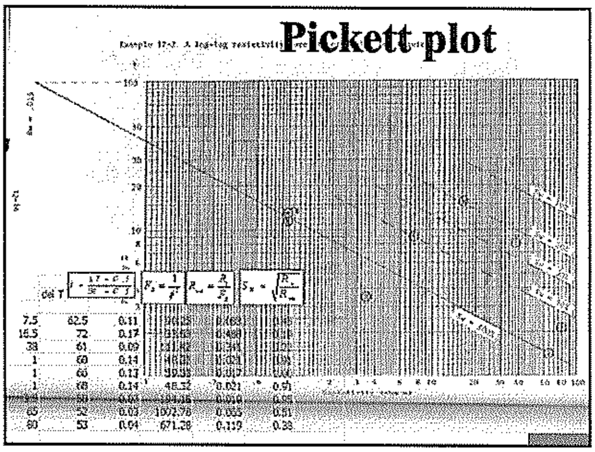
Pickett plot

The Pickett plot requires the following steps:

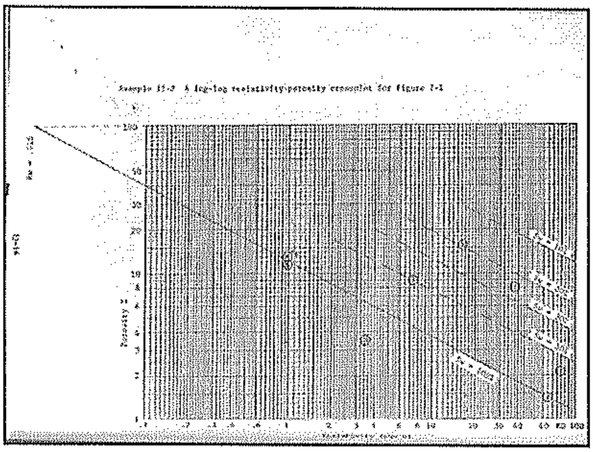
1. Tabulate the porosity and the corresponding resistivity values for the expected hydrocarbon-bearing formations and the possible nearby 100% water-saturated formations. Use crossplot porosities if two porosity logs are run.
2. Plot the data on a log-log (two cycle by three cycle preferred) graph paper.
3. On the plot, a zone with constant R_w, m, and S_w = 100% will have data points plotted along a single straight-line trend. Draw a best-fit straight line through these points. This straight-line trend represents the R_o line.
4. Determine the slope of the R_o line. The slope of this line is equal to the cementation factor (m). The R_t at which this line intersects ϕ = 100% represents aR_w.
5. Data plotted above the R_o line represent water saturation values less than 100%. This is true only when R_w and m are both constant.
6. A quick look assessment of a zone's water saturation can be made by drawing various water saturation lines parallel to the R_o line. The position of the various water saturation lines is determined using Equation (3.33).
7. To construct additional water saturation lines on the graph (a) draw a horizontal line to the right, beginning at the point where the R_o line crosses the porosity scale (ϕ = 0.1, 1.0, 10.0, etc.) (i.e., R_t = R_o = 0.1, 1.0, 10.0, etc.); (b) on this line mark the R_ts which correspond to the indicated water saturations. Remember that for R_o = 1.0, R_t = $1/S_w^2$ or R_t = R_o/S_w^2.

When Δt_{LOG} − Δt_{ma} or ρ_{ma} − ρ_b are plotted versus R_t using incorrect matrix value, the R_o line for Δt_{LOG} − Δt_{ma} or ρ_{ma} − ρ_b versus R_t plot will not plot as a straight line, but will curve. In

Pickett plot



	del T		$F_R = \frac{1}{\phi^2}$	$R_{wa} = \frac{R_t}{F_R}$	$S_w = \sqrt{\frac{R_w}{R_{wa}}}$
7.5	62.5	0.11	[illegible]	[illegible]	[illegible]
16.5	72	0.17	[illegible]	[illegible]	[illegible]
38	61	0.09	[illegible]	[illegible]	[illegible]
1	60	0.14	[illegible]	[illegible]	[illegible]
1	60	0.13	[illegible]	[illegible]	[illegible]
1	60	0.14	48.32	0.021	0.91
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
65	52	0.03	1002.78	0.065	0.51
80	53	0.04	671.28	0.119	0.38



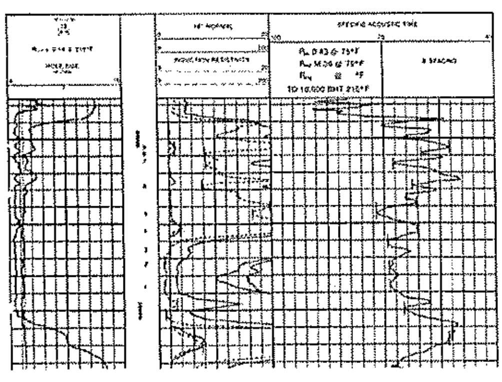


Figure 3–55. Log section for Example 3–17 (courtesy of Atlas Wireline Services).[5]

TABLE 3–8. Log data for the log in Figure 3–55

Zone	Δt_{LOG}	R_{ILD}	$\Delta t_{LOG} - \Delta t_{ma}$	ϕ
1	68.8	1.00	21.3	0.15
2	68.5	1.10	21.0	0.15
3	69.5	2.10	22.0	0.16
4	61.0	4.00	13.5	0.10
5	72.3	16.5	24.8	0.18
6	62.5	7.50	15.0	0.11
7	67.8	8.30	20.3	0.14
8	60.0	6.20	12.5	0.09
9	52.0	28.0	4.50	0.03

To find the S_w for the nine zones, we construct water saturation lines for S_w = 80%, 60%, 40%, 20%, and 10% on Figure 3–56, using ϕ = 10% and R_t as given below.

ϕ	S_w	R_o	$R_t = R_o/S_w^2$
0.10	80	2.4	3.75
0.10	60	2.4	6.67
0.10	40	2.4	15.00
0.10	20	2.4	60.00
0.10	10	2.4	240.00

The Hingle Crossplot. The Hingle crossplotting technique is a powerful technique allowing a long section of well logs to be analyzed in a minimum of time. The advantage of Hingle plot over the

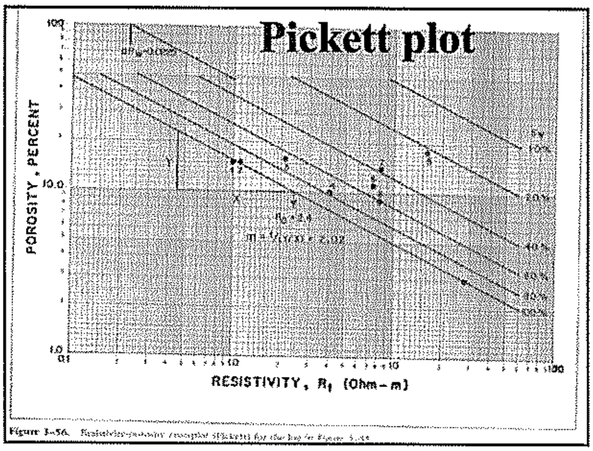
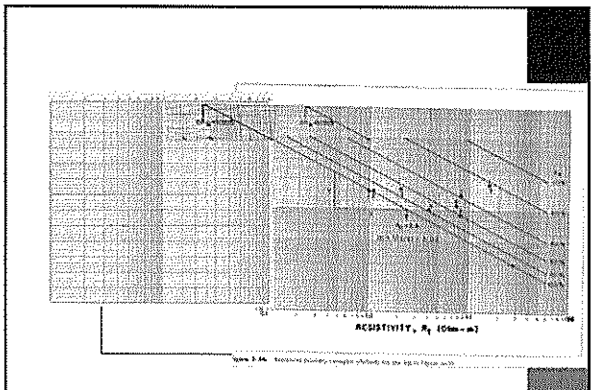
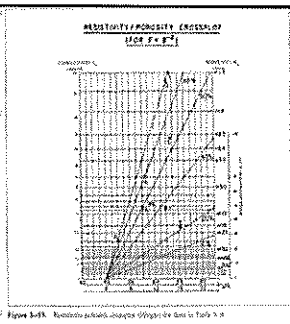
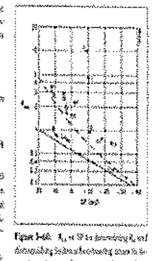


Figure 3-56. Resistivity-porosity crossplot (Pickett) for the log in Figure 3-55.







R_w FROM R_{wa}–SP PLOT[3]

A plot of R_{wa} ($R_{wa} = R_t/F_R$) on logarithmic scale versus SP deflection on linear scale can be used to estimate R_w. This plot is much valuable at shallow depths when R_w can change rapidly. The rapidly changing R_w makes it difficult to determine R_w from SP log.

Figure 3-60 is a plot of R_{wa} versus SP from an interval where R_w changes rapidly. The R_{wa} and the corresponding SP values when plotted on semilogarithmic graph paper will show a trend parallel to and just above the R_w line. R_w as computed from the SP curve. This indicates slightly greater than average amounts of salts other than NaCl. The hydrocarbon-bearing formations are identified by data points falling above the main trend, such as the Points 5 and 11 in Figure 3-60.

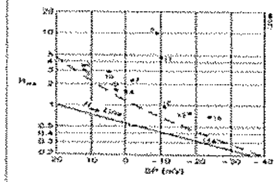


Figure 3-60. R_{wa} vs. SP for determining R_w and distinguishing hydrocarbon-bearing zones in intervals of changing R_w (courtesy of Schlumberger).[3]

R_w FROM R_{xo} AND R_t[3]

The R_{xo}, R_{mf} and R_t are related to each other by the following equation:

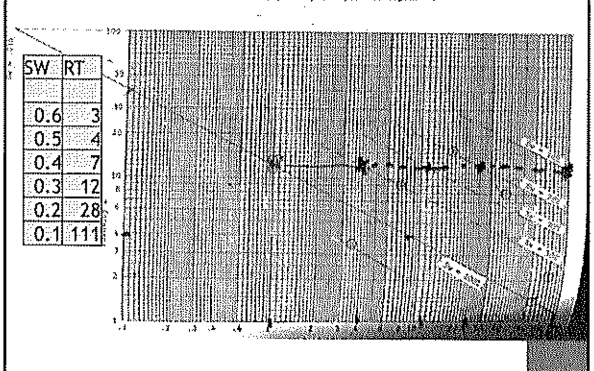
$$\frac{R_{xo}}{R_t} = \left(\frac{S_w}{S_{xo}}\right)^2 \frac{R_{mf}}{R_w} \qquad (3.36)$$

In 100% water saturated zones, $S_w = S_{xo} = 1.0$ (i.e., 100%), and R_{xo}/R_t is equal to R_{mf}/R_w. Thus by computing R_{xo}/R_t over an interval containing clean, invaded-water sands, the value of R_{mf}/R_w can be found. Then, knowing R_{mf}, R_w can be determined.

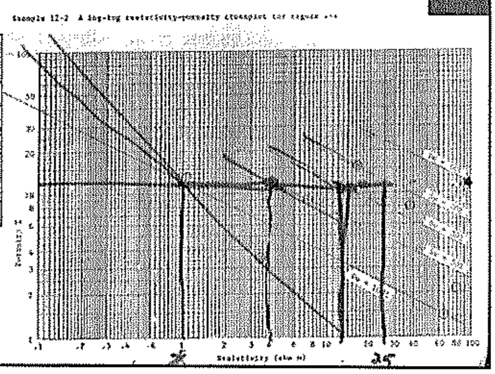
A similar result can be obtained by plotting R_{xo} values (from microspherically focused log or Proximity log) versus the corresponding R_t values (from a deep resistivity log) over an interval containing some water sands. A line through the points corresponding to the highest values of R_{xo}/R_t provides an estimate of R_{mf}/R_w.

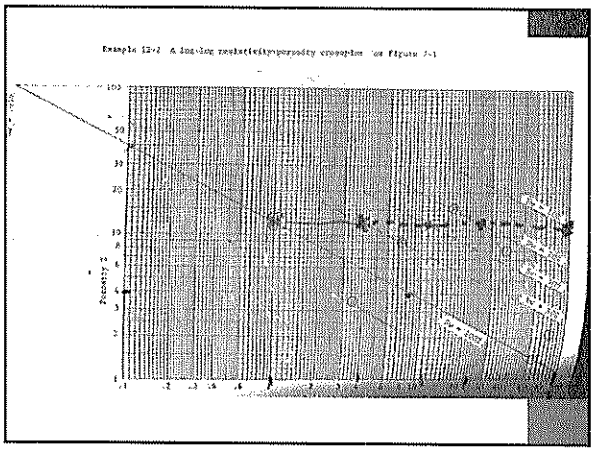
Example 11-2 A log-log resistivity-porosity crossplot of Figure 7-1

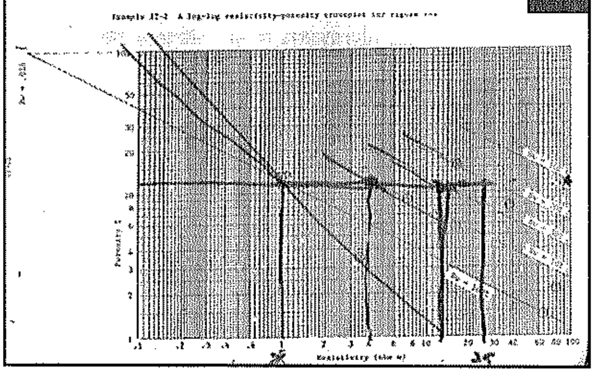
SW	RT
0.6	3
0.5	4
0.4	7
0.3	12
0.2	28
0.1	111

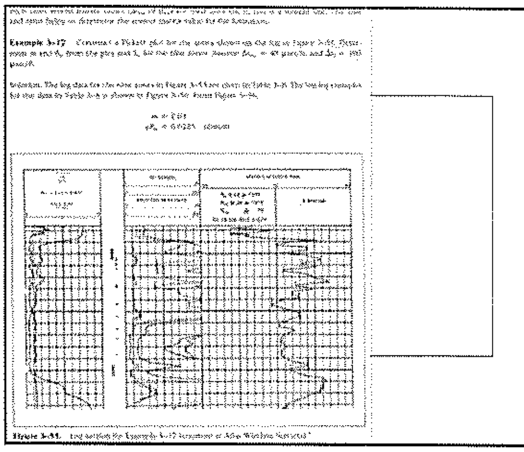


SW	RT
0.6	3
0.5	4
0.4	7
0.3	12
0.2	28
0.1	111









DETAILED LOG ANALYSIS: PERMEABILITY

Permeability can be estimated from porosity, resistivity, Sw and hydrocarbon density data. However, Sw must equal Swirr, the irreducible water saturation.

Bulk Volume Water (BVW) must be calculated and plotted in advance to made sure the zone of interest is at Swirr.

DETAILED LOG ANALYSIS: PERMEABILITY

There are two simple formulas for medium gravity oil and dry gas (i.e. hydrocarbon density is assumed.

For medium gravity oil:

$$Q = \frac{KA(P_1 - P_2)}{\mu L}$$

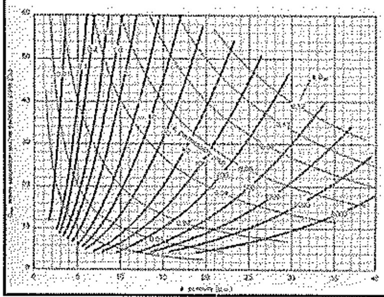
$$K = \left(250 * \frac{\Phi^3}{S_{wirr}}\right)^2$$

For dry gas:

$$K = \left(79 * \frac{\Phi^3}{S_{wirr}}\right)^2$$

DETAILED LOG ANALYSIS: PERMEABILITY

$$K = \left(250 * \frac{\Phi^3}{S_{wirr}}\right)^2$$



The equations can be solved graphically. Each hydrocarbon density requires a separate graph.

DETAILED LOG ANALYSIS: PERMEABILITY

A more complicated formula that includes variables for hydrocarbon density is:

$$C \cong 23 + 465\rho_h - 188\rho_h^2$$

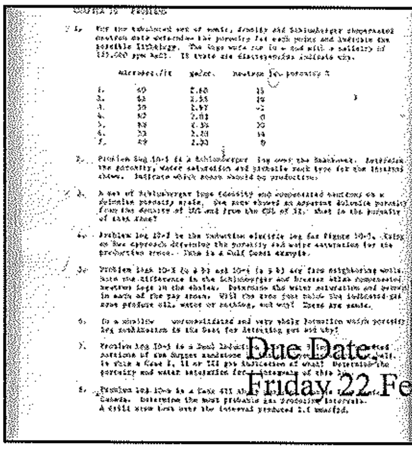
$$W \cong \sqrt{3.75 - \Phi + \frac{1}{2}\left(\log\left(\frac{R_w}{R_{irr}}\right) + 2.2\right)^2}$$

$$K \cong \left(\frac{C * \Phi^{2W}}{W^4 * \left(\frac{R_w}{R_{irr}}\right)}\right)^2$$

DETAILED LOG ANALYSIS: PERMEABILITY

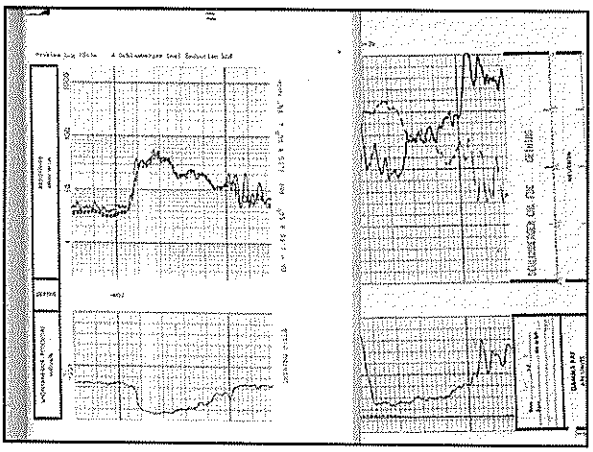
The most reliable permeability comes from well testing and direct measurements of discharge and hydrocarbon density. If cores are available, permeability can be measured in the lab.

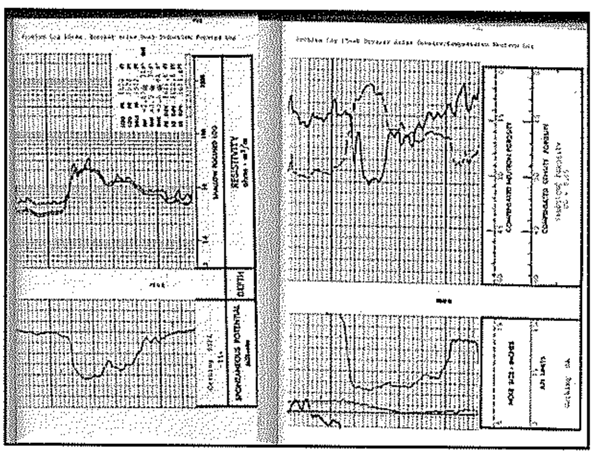
$$Q = \frac{KA(P_1 - P_2)}{\mu L}$$

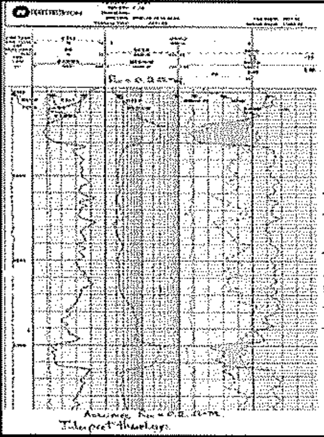


HW NO.
Chapter 10
Problem 1, 3 and 5
And in HAND OUT SHEET

Due Date:
Friday 22 February.2013







Interpret the logs
Assuming clean
Sand Stone and
$R_w = 0.2 \Omega$-m

HW NO 10 QUICKLOOK
Chapter 11; 11.2, and 11.4
Chapter 12; 12.4 and 12.5 In HILCHIE TEXT
And Chapter12; , 12.6 and 12.10,
Chapter 13; 13.4, and 13.9 In SPE TEX T, DUE 11 March 2[illegible]

12.6 Fig. 12.25 illustrates an R_o log. The log is derived from an F log that is normalized in Water Zone B.
a. Does Zone A contain hydrocarbons? Explain.
b. Give the average water saturation in the top 5 ft of Zone A.
c. Calibrate the R_o curve in porosity units; then determine the average porosity of the top 5 ft of Zone A.
d. What is the value of R_w in this interval?

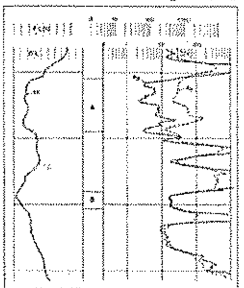


Fig. 12.25—Log data for Problem 12.6 (courtesy Schlumberger).

13.4 Fig. 13.25 shows the Hingle plot prepared for permeable zones present in a 200 ft interval. The R_t values are derived from the dual induction/SFL log, and the porosity values are derived from the bulk density log using a matrix density value of 2.73 g/cm³. If the subject interval is known to contain two types of lithology, explain the two lithology types and determine the value of R_w in each lithology type. If hydrocarbons are present in the subject interval, the hydrocarbons are expected to be oil. Does Zone A shown on the plot contain oil? If yes, what is the oil saturation?

Problem 13.3 d. $m=2$.
Problem 13.4 a. Limestone and sandstone.
b. 0.05 and 0.09 Ω·m.
c. Zone A is more likely to belong to the limestone pattern because of its low porosity. S_o=50%.
Problem 13.5 c. Yes. Zones 5 and 9.
d. R_w=0.05 Ω·m, Δt_{ma}=56 μsec/ft.
e. R_w=0.04 Ω·m, m=2.1
f. Zones 1, 2, 8, and 11.
Problem 13.6 a. Different lithology.
b. Unconsolidated sands, Δt_{ma}=115 μsec/ft.
c. No, the presence of shale results in water saturation values higher than the true ones.
Problem 13.7 e. Sandstone: m=1.9, R_w=0.16 Ω·m
Limestone: m=2.23, R_w=0.5 Ω·m.
Problem 13.8 a. m=2.
b. R_w=0.011 Ω·m
Problem 13.9 a. Yes, tight zones.
b. Yes, the same R_w values are obtained from the two plots.
c. No.

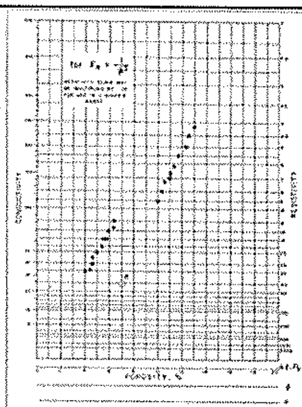


Fig. 13.25—Hingle plot of problem 13.4.

13.9 An exploration well was drilled to test sands in the interval 18,790 to 18,960 ft shown in Fig. 13.28. Only a dual induction/sonic log was obtained. The openhole condition precludes the acquisition of additional data (logs, cores, formation tester, drillstem test, etc.). Further testing will require running a casing, which, given the formation depth, represents a substantial investment.

Twenty-one zones, marked on the log, were selected for the analyses. Hingle and Pickett plots were prepared and are shown in Figs. 13.29 and 13.30.

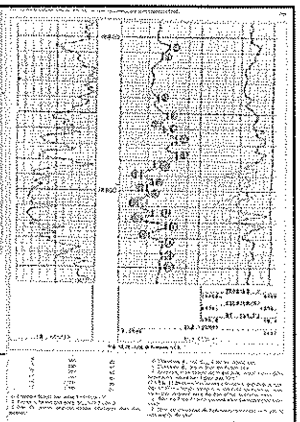
a. Are lithologies other than sandstone present in the interval analyzed?

b. Is the analyst justified in using $m=2$ and $\Delta t_{ma}=55$ μsec/ft in constructing the two crossplots?

c. Does the interval analyzed contain potential hydrocarbon zones?

d. If experience with this formation indicates that R_w=0.06 Ω·m at formation temperature, will this affect the conclusion you reached in Part c, and how do you explain the difference between this R_w value and the value obtained from the crossplots?

e. In the form of a memorandum, give your recommendations as to what to do next with this well.



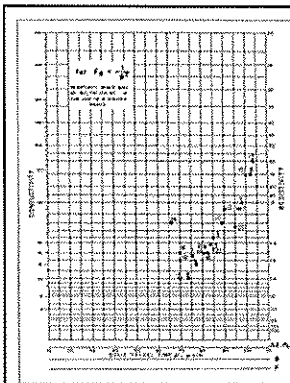


Fig. 13.29—Hingle plot of Problem 13.9.

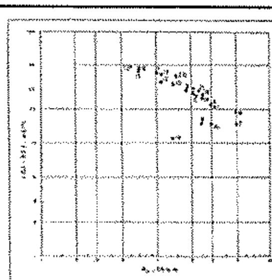


Fig. 13.30—Pickett plot of Problem 13.9.

3	80	52
4	55	54
5	128	49
6	8	52
7	5	54
8	1.9	58
9	4	55
10	2.4	59

CHAPTER13

Go

SHALY SAND INTERPRETATIONS

434359,505359 WELL LOGGING 2013(3/2555)

COURSE OUTLINES

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)
Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)
Resistivity Device(2 hrs.)
Spontaneous Potential (SP) Log(2 hrs.)
Induction Electric and Dual Induction Logs(2 hrs.)
Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Fracture Detection with Well Logs(1 hr.)
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)

Ch13 Shaly Sandstone Interpretation

Shale — laminated Shaly S.S or Structural
— Dispersed " "

ลด K, ϕ

Shale correction → reduce S_w (V_{sh} > 10-15%)

LOG Influences

ทำให้ต่ำ

Rt ↓ ค่าลด cal Sw สูงกว่าจริง

SP ↓ ค่าลด

GR ↑ สูง

Density ϕ ↑ ถ้าเป็น Montmorillonite มากกว่า Illite ρ_m = 2.76 g/cc

Neutron ϕ ↑

Acoustic ϕ ↑ if laminated or Structural
non effect if dispersed

Quick Shaly Sand Method

V_{sh}	15%	S_w ลด	5%
	30		10
	45		15

$S_w = \sqrt{\frac{F R_w}{R_t}} - \frac{V_{sh} R_w}{\ldots}$

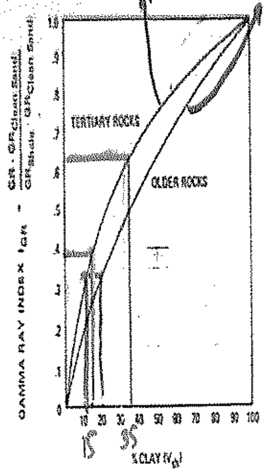
Gamma Ray Shale Volume:

A relationship between shale volume and the relative gamma ray deflection (gamma ray index) is shown in figure 13-1. The gamma ray index is a mathematical means of normalizing the gamma ray deflection between a clean sand (gamma ray index =0) and a shale (gamma ray index = 1). This prevents units and calibration problems.

$V_{sh} = 0.083(2^{3.7 I_{GR}} - 1)$

Figure 13-1 Determination of shale content from the gamma ray

$V_{sh} = 0.33(2^{2 I_{GR}} - 1)$



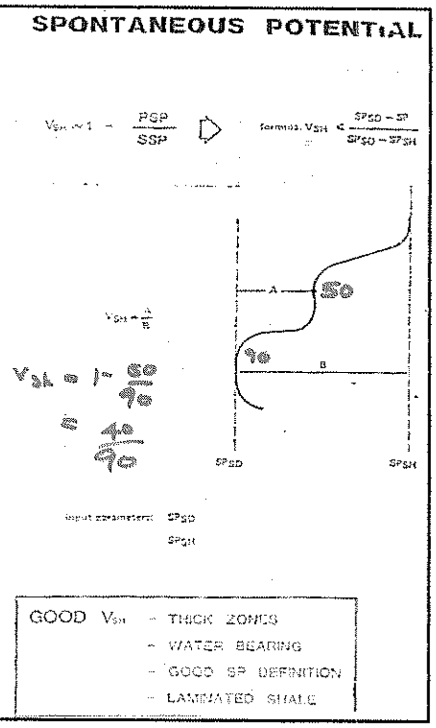
Volume of shale

- The volume of shale in a sand is used in the evaluation of shaly sand reservoirs.
- It can be calculated by
  - Spontaneous Potential
  - Gamma Ray

V_{sh} by SP

$$V_{sh} = 1.0 - \frac{PSP}{SSP} \quad \text{or} \quad V_{sh} = \frac{PSP - SSP}{SP_{shale} - SSP}$$

- With
  - PSP, Pseudostatic Spontaneous Potential (max. SP of shaly formation)
  - SSP, Statis Spontaneous Potential of a nearby thick clean sand
  - SP_{shale}, value of SP in shale, usually assumed to be zero



V_{sh} by GR

Gamma Ray index

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

I_{GR} = Gamma Ray index | GR_{log} = GR reading from the log
GR_{min} = minimum GR | GR_{max} = maximum GR

$V_{shale} = I_{GR}$, Linear response, 1st order estimate

$V_{shale} = 0.08(2^{3.7 I_{GR}} - 1)$, Larionov (1969), Tertiary rocks

$V_{shale} = \frac{I_{GR}}{3 - 2 \times I_{GR}}$, Steiber (1970)

$V_{shale} = 1.7 - [3.38 - (I_{GR} - 0.7)^2]^{1/2}$, Clavier (1971)

$V_{shale} = 0.33 \times (2^{2 I_{GR}} - 1)$, Larionov (1969), for older rocks

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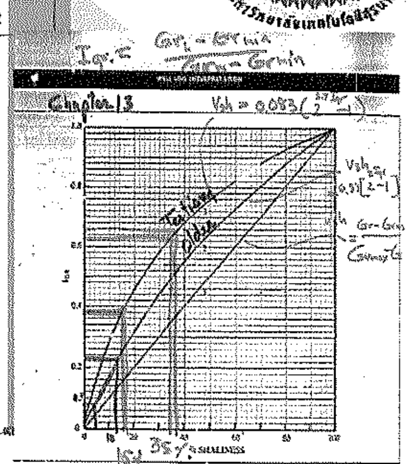

...re 5-13. Chart for converting the gamma ray index (I_{GR}) to the volume of shale (V_{sh}) (courtesy ... Atlas Wireline Services).

CLAY INDICATORS

Single Curve Indicators — Favorable Conditions

Indicator	Favorable Conditions
$(V_{cl})_{SP} = 1 - \dfrac{SP}{SSP}$	laminated shale and Water bearing zone or low resistivity
$(V_{cl})_{GR} = \dfrac{GR_{Log} - GR_{min}}{GR_{max} - GR_{min}}$	clay is only radioactive mineral and clay has constant radioactivity
$(V_{cl})_R = \left[\dfrac{R_{cl}}{R_t} \cdot \dfrac{R_{lim} - R_t}{R_{lim} - R_{cl}}\right]^{1/b}$ where: $b = 2$ For $\dfrac{R_{clay}}{R_T} \leq 0.5$; $b = 1$ For $0.5 < \dfrac{R_{clay}}{R_T} \leq 1$	Medium to high resistivity, or high hydrocarbon content, or low water content, or low porosity
$(V_{cl})_N = \left[\dfrac{\Phi_N}{\Phi_{Ncl}} \cdot \dfrac{\Phi_N - \Phi_{lim}}{\Phi_{cl} - \Phi_{lim}}\right]^{\frac{1}{2}}$ for $\Phi_{lim} > 0$	gas bearing formation
$(V_{cl})_N = \dfrac{\Phi_N}{\Phi_{Ncl}}$ for $\Phi_{lim} \simeq 0$	low porosity formation

older consolidated

$V_{sh} = 0.33(2^{2 \times I_{gr}} - 1)$

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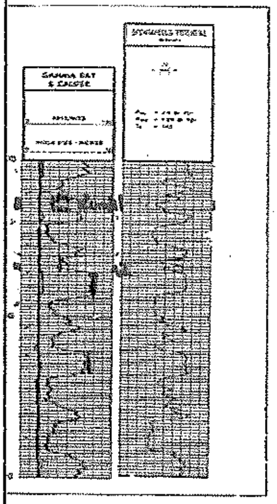


3–12. Comparison of gamma ray and ... courtesy of Atlas Wireline Services).

For tertiary and consolidated rocks:

$V_{sh} = 0.083\,[2^{(3.7 \times I_{GR})} - 1.0]$ (3.6

Example 3–5. Determine the volume of sha[le] for the zones 5,524–5,530 ft (Zone 1) and 5,566 5,568 ft (Zone 2) in the gamma ray log presente[d] in Figure 3–12. Assume older rocks.

Solution: From the log,

$GR_{max} = 80$ 5,573–5,583 ft
$GR_{min} = 28$ 5,540–5,546 ft
$GR_{zone1} = 32$ $GR_{zone2} = 40$

$$(I_{GR})_{zone1} = \frac{32 - 28}{80 - 28} = 0.08$$

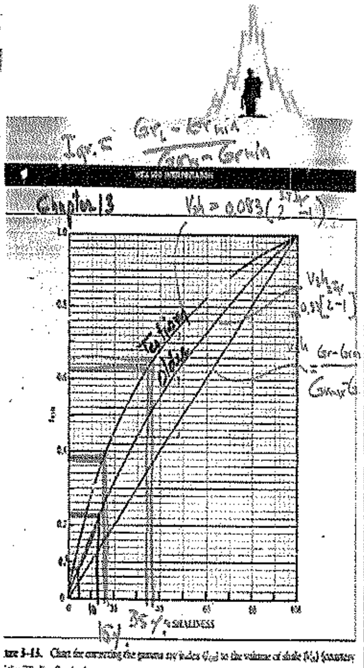
$$(I_{GR})_{zone2} = \frac{40 - 28}{80 - 28} = 0.23$$

Using Equation (3.7), the volume of shale wou[ld] be:

$$V_{sh(zone1)} = 0.33\,(2^{(2 \times 0.08)} - 1.0) \times 100 = 3.87\%$$

$$V_{sh(zone2)} = 12.39\%$$

The caliper log is used to measure the diame[ter] of the wellbore in inches from the top of the h[ole] to the bottom. The size of the hole is requi[red] for correcting some of the logs for hole size effe[cts] and it also helps in determining hole volume [in] order to estimate the amount of cement requ[ired for ce]menting the casing. The log will show if ther[e] is any swelling or washout, etc., in the hole. T[he] log is run in conjunction with the SP log or the GR log.



[Fig]ure 3-13. Chart for correcting the gamma ray index (I_{GR}) to the volume of shale (V_{sh}) (courtesy of Atlas Wireline Services).

Spectralog Gamma ray spectral logging provides individual measurements of potassium (K, %) and thorium (Th, ppm) content	$V_{cl} = (A - A_{min})/(A_{max} - A_{min})$ $V_{cl} = C(A - A_{min})/(A_{max} - A_{min})$ $V_{cl} = 0.33(2^{2A} - 1.0)$ $V_{cl} = 0.083(2^{3.7A} - 1.0)$	Coefficient C similar to gamma ray discussion. A = Spectralog readings (K in %, Th in ppm). A_{min} = minimum value (K or Th) in clean zones, A_{max} = maximum values (K, Th) in essentially pure shales.	Similar to gamma ray discussion. However, uranium enrichment in permeable, fractured zones and radiobarite buildup are no limitations. If Th curve is used, localized heavy mineral streaks should be ignored.
Resistivity If several resistivity logs are available, use the one that exhibits highest resistivity values in subject well	$V_{cl} = (R_{cl}/R_t)^{1/b}$ where b = 1.0 b = 2.0	Low-porosity zones (carbonate matrix); pay zones with low ($S_w = S_{wi}$) R_{cl}/R_t from 0.5 to 1.0. R_t approaches R_{cl}	High-porosity water sand, high R_w values.
	$V_{cl} = [R_{cl}(R_{max} - R_t)/R_t(R_{max} - R_{cl})]^{1/b}$ where $(1/b) = 1.0$ when $R_{cl}/R_t \geq 0.5$ $(1/b) = 0.5/(1 - R_{cl}/R_t)$ when $R_{cl}/R_t < 0.5$	In clean hydrocarbon-bearing zones, $V_{cl} = 0$.	
Neutron	$V_{cl} = \phi_N/\phi_{Ncl}$	High gas saturation or very low effective porosity.	ϕ_{Ncl} is low
	$V_{cl} = (\phi_N - \phi_{Nmin})/(\phi_{Ncl} - \phi_{Nmin})$	ϕ_{Nmin} can be varied.	
Pulsed Neutron	$V_{cl} = (\Sigma - \Sigma_{min})/(\Sigma_{max} - \Sigma_{min})$	Freshwater environment; low-porosity and gas-bearing zones.	
	$V_{cl} = (\Sigma_{cl}/\Sigma)(\Sigma - \Sigma_{min})/(\Sigma_{max} - \Sigma_{min})$		
Density/Neutron	$V_{cl} = \frac{[illegible]}{[illegible]}$		Too low V_{cl} in prolific gas zones; Not for use in severe hole conditions.

TABLE 3-12. Log-derived clay volume indicators

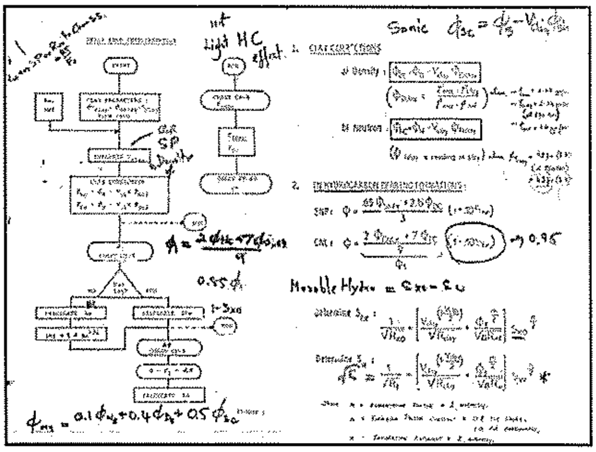
Logging Curve	Mathematical Relationship	Favorable Conditions	Unfavorable Conditions
Spontaneous Potential (SP curve)	$V_{cl} = 1.0 - (PSP/SSP) = 1.0 - \alpha$	Water-bearing, laminated shaly sands	$R_{xo}/R_w \leq 1.0$. Thin, high R_t zones. Hydrocarbon-bearing. Large electrokinetic and/or invasion effects.
	$V_{cl} = (PSP - SP_{cl})/(SSP - SP_{cl})$	c ≤ 1.0 as function of clay type	
	$V_{cl} = 1.0 - \alpha c$ $1.0 - \alpha = \log A/\log[(A - V_{cl}B)/(1 - V_{cl}B)]$ where $A = R_t/R_{xo}$ $B = R_t/R_{cl}$	Knowledge of several parameters required, including a, R_t, R_{xo} and R_w. Similar limitations as for straightforward SP equations.	
	$1.0 - \alpha = (KV_{cl}W)/(KV_{cl}W + \phi S_{xo})$	K = logarithmic coefficient; W = clay porosity from bulk and matrix ρ; S_{xo} = flushed zone water saturation; laboratory-derived to ensure requirements.	
Gamma Ray (GR)	$V_{cl} = (GR - GR_{min})/(GR_{max} - GR_{min})$	Only clay minerals are radioactive.	Radioactive minerals other than clays (mica, feldspar, and silt).
	$V_{cl} = C(GR - GR_{min})/(GR_{max} - GR_{min})$	C ≤ 1.0, approximately 0.5 when V_{cl} < 40%.	Only potassium-deficient kaolinite present. Uranium enrichment in permeable, fractured zones.
	$V_{cl} = (GR - W)/Z$, where W, Z = geologic area coefficients.		Radioactive scales on casing. Severe washouts (GR).
	$V_{cl} = 0.33(2^{2I_{GR}} - 1.0)$**	Highly consolidated and Mesozoic rocks	Younger, unconsolidated rocks
	$V_{cl} = 0.083(2^{3.7I_{GR}} - 1.0)$**	Tertiary rocks.	Older, consolidated rocks.

TABLE 3-13. Continued

Reference	Equation*	Type**	Comments†
Doll	$C_t = \frac{C_w}{F}S_w^2 + 2V_{sh}\sqrt{\frac{C_wC_{sh}}{F}}S_w + V_{sh}^2C_{sh}$	3	
Alger et al.	$C_t = \frac{C_w(1-q)^2}{F}S_w^2 + \frac{q(1-q)(C_w + C_{cl})}{F}S_w + \frac{q^2C_{cl}}{F}$	3	Clay slurry model. f relates to total volume occupied by fluid and clay. S_w relates to fluid-filled pore space.
Hossin and Anton	$C_t = \frac{C_w}{F}S_w^2 + 2V_{sh}\sqrt{\frac{C_wC_{sh}}{F}}\left(1 - \sqrt{\frac{C_w}{C_{sh}}}\right)S_w + V_{sh}^2C_{sh}\left(1 - \sqrt{\frac{C_w}{C_{sh}}}\right)^2$	3	F = $1/\phi_t^2$ where ϕ_t is the total interconnected porosity. $C_w = C_{eq}$. S_w relates to total interconnected pore space.
[illegible]	$C_t = \frac{(1 - V_{sh})C_w}{F}S_w^2 + \frac{(1 - V_{sh})}{F}B Q_v S_w + V_{sh}C_{sh}$	3	Laminated sand-shale model. V_{sh} = volume fraction of laminated shales only. F relates to total interconnected porosity within shaly-sand streaks. S_w relates to total interconnected pore space within shaly-sand streaks.
	$\frac{1}{R_t} = \frac{1}{R_wF}S_w^2 + \sqrt{\frac{V^{2-V}}{F_w R_{sh}}}S_w$		
Poupon and Leveaux	$C_t = \frac{C_w}{F}S_w^2 + 2\sqrt{\frac{C_wV_{sh}^{2-V_{sh}}C_{sh}}{F}}S_w^2 + V_{sh}^{2-V_{sh}}C_{sh}S_w^2$	4	"Indonesia" formula.
Poupon and Leveaux	$C_t = \frac{C_w}{F}S_w^2 + 2\sqrt{\frac{C_wV_{sh}C_{sh}}{F}}S_w^2 + V_{sh}C_{sh}S_w^2$	4	Simplified Indonesia formula for $V_{sh} \leq 0.5$

TABLE 3-12. Continued

Logging Curve	Mathematical Relationship	Favorable Conditions	Unfavorable Conditions*
Density/Acoustic	$V_{cl} = \frac{[illegible]}{[illegible]}$	Less dependent on lithology and fluid conditions than density/neutron crossplot. Use in gauge boreholes.	Badly washed out wellbores. Highly undercompacted formations (shallow, overpressured)
Neutron/Acoustic	$V_{cl} = \frac{[illegible]}{[illegible]}$	Use only in gas-bearing zones with low S_w	Similar effects because of shaliness on both logs.



Sonic $\phi_{sc} = \phi_s - V_{clay}\phi_{sh}$

1. CLAY CORRECTIONS

a) Density : $\boxed{\Phi_{DC} = \Phi_D - V_{clay}\Phi_{Dclay}}$

$\left(\Phi_{Dclay} = \frac{\rho_{ma} - \rho_{clay}}{\rho_{ma} - \rho_{mf}}\right)$ where, $-\rho_{ma} = 2.65$ gr/cc; $-\rho_{clay} = 2.34$ gr/cc (at 870 feet); $-\rho_{mf} = 1.0$ gr/cc

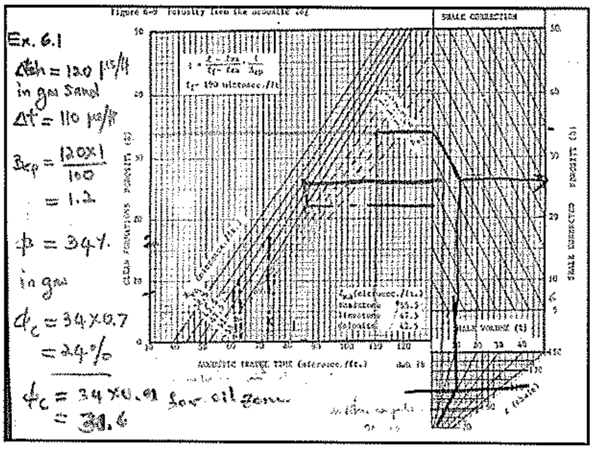
b) Neutron : $\boxed{\Phi_{NC} = \Phi_N - V_{clay}\Phi_{Nclay}}$

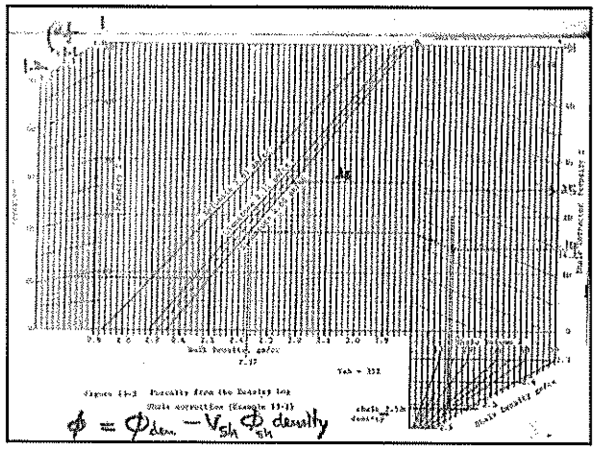
(Φ_{Nclay} is reading in clay) where $\phi_{N_{clay}}$ = 38 pu (LS) (at 850 feet) = 42 pu (S.S)

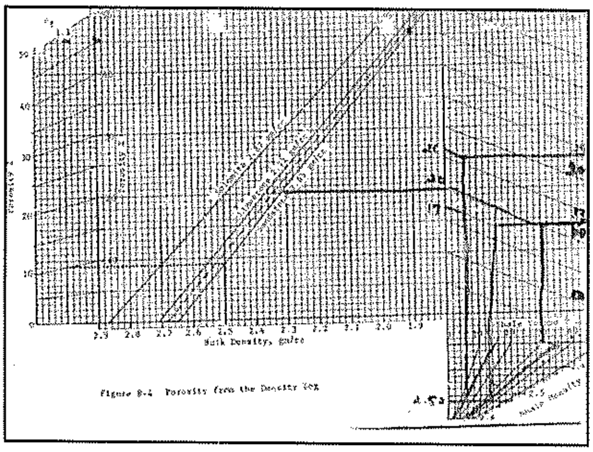
2. IN HYDROCARBON BEARING FORMATIONS :

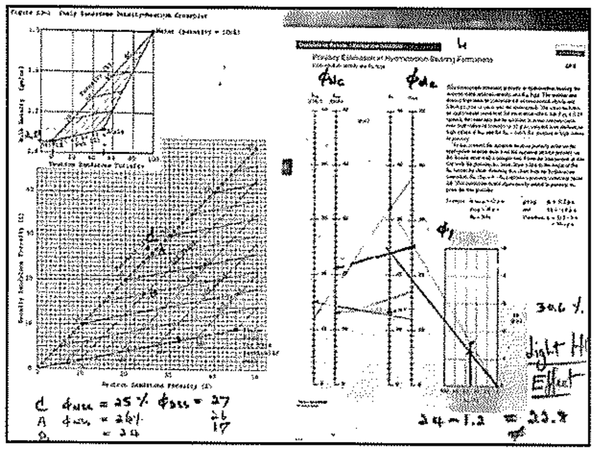
SNP: $\Phi = \frac{.85\,\Phi_{SNPc} + 2.15\,\Phi_{DC}}{3}(1 - .10S_{hr})$

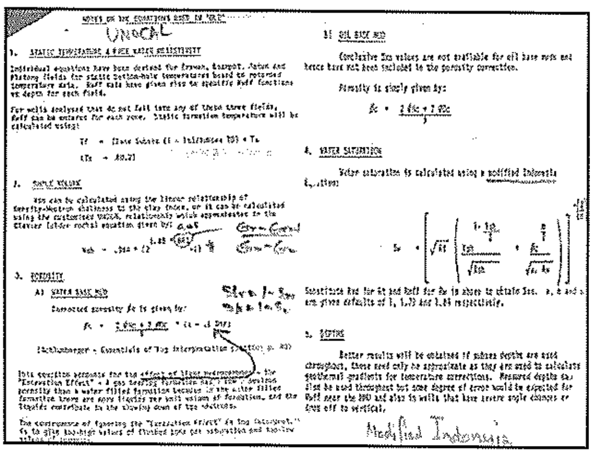
CNL: $\Phi = \frac{2\,\Phi_{CNLc} + 7\,\Phi_{DC}}{9}(1 - .10S_{hr}) \rightarrow 0.95$

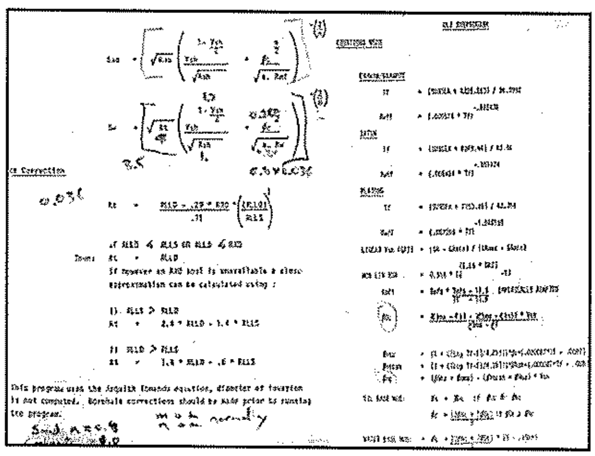

Ex. 6.1
Δth = 120 μs/ft in gas sand
Δt = 110 μs/ft
Bcp = 120×1/100 = 1.2
φ = 34% in gas
φc = 34×0.7 = 24%
φc = 34×0.9 = 31.6 for oil zone


φ = φden − Vsh φsh density




30.6 %
light HC Effect
24 − 1.2 = 22.8





Patchett and Rausch	$C_t = \frac{C_w}{F} S_w^2 + C_s S_w$	2	C_s = conductivity due to shale (≠ C_{sh}). F relates to total interconnected porosity. S_w relates to total interconnected pore space.
Waxman and Smits	$C_t = \frac{C_w}{F^*} S_w^2 + \frac{BQ_v}{F^*} S_w$	2	F^* relates to total interconnected porosity. S_w relates to total interconnected pore space.
Bardon and Pied	$C_t = \frac{C_w}{F} S_w^2 + V_{sh} C_{sh} S_w$	2	Modified Simandoux equation.
Schlumberger	$C_t = \frac{C_w}{F(1 - V_{sh})} S_w^2 + V_{sh} C_{sh} S_w$	2	F relates to the free fluid porosity of the total rock volume, inclusive of intraformational (laminated) shales.
Clavier et al	$C_t = \frac{C_w}{F_o} S_w^2 + \frac{(C_{bw} - C_w) V_Q Q_v}{F_o} S_w$	2	Dual-water model. F_o relates to total interconnected porosity. S_w relates to the total interconnected pore space.
Juhasz	$C_t = \frac{C_w}{F} S_w^2 + \left(\frac{C_{sh}}{F_{sh}} - C_w\right) \frac{V_{sh} \phi_{sh} S_w}{\phi}$	2	Normalized Waxman-Smits equation. $F = 1/\phi^m$ where ϕ is the porosity derived from the density log and corrected for hydrocarbon effects. $F_{sh} = 1/\phi_{sh}^m$ where ϕ_{sh} is the shale porosity derived from the density log. S_w relates to total interconnected pore space.

ample, in the case of bulk density as measured by a density log, the relationship is

$$\varrho_b = \phi\,(S_{xo}\,\varrho_{mf} + S_{hr}\,\varrho_h) + V_{sh}\,\varrho_{sh} + (1 - \phi - V_{sh})\,\varrho_{ma}, \quad \text{(Eq. 2-13)}$$

where V_{sh} is the bulk-volume fraction of shale, ϱ_{sh} is its density, ϱ_h is the apparent density of the hydrocarbon, and the other terms are as previously defined.

There are many formulas that relate resistivity to water saturation in shaly sands. Most are generally of the form

$$\frac{1}{R_t} = \frac{S_w^2\,(1 - V_x)}{FR_w} + \frac{CV_x}{R_x}, \quad \text{(Eq. 2-14)}$$

where V_x is a term related to the volume, or some specific volumetric characteristic, of the shale or clay; R_x is a term related to the resistivity of the shale or clay; and C, if it occurs in the formula, is a term related to the water saturation, S_w.

e second step is to correct the porosity logs for shale content (refer to discussion on porosity combination of density-neutron logs are run, the following equations are used to correct , for shale:

$$\phi_{N\text{-}corr} = \phi_N - \left[\left(\frac{\phi_{N\text{-}clay}}{0.45}\right) \times 0.30 \times V_{sh}\right] \quad (3.50)$$

$$\phi_{D\text{-}corr} = \phi_D - \left[\left(\frac{\phi_{D\text{-}clay}}{0.45}\right) \times 0.13 \times V_{sh}\right] \quad (3.51)$$

$$S_w = \frac{0.4 R_w}{\phi^2} \times \left[\frac{-V_{sh}}{R_{sh}} + \sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{5\phi^2}{(R_t R_w)}}\right] \quad (3.52)$$

...rtl Equation, where a = 0.25 for Gulf Coast ...d a = 0.35 for Rocky Mountains:

$$S_w = \frac{1}{\phi} \times \left[\sqrt{\frac{R_w}{R_t} + \left(\frac{a \times V_{sh}}{2}\right)^2} - \frac{a \times V_{sh}}{2}\right] \quad (3.53)$$

...lumberger Equation:

$$S_w = \frac{\frac{-V_{sh}}{R_{sh}} + \sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{\phi^2}{0.2 \times R_w (1 - V_{sh}) R_t}}}{\frac{\phi^2}{0.4 \times R_w (1 - V_{sh})}} \quad (3.54)$$

...ample 3-23. Figure 3-71 shows dual induction focused log, compensated density log, ...mpensated neutron log, and gamma ray log for ...dell-Niobrara formation in Weld County, Colorado. Using shaly formation analysis, calculate ...ter saturation for the zone at 6,586–6,598 ft ...se Schlumberger Equation). Other data from the log heading are

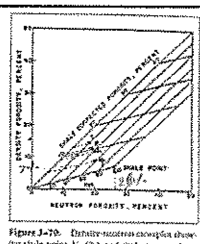


Figure 3-70. Density-neutron crossplot showing shale point, V_{sh} (%), and shale-corrected porosity.

Fertl Equation, where a = 0.25 for ... and a = 0.35 for Rocky Mountains:

$$S_w = \frac{1}{\phi} \times \left[\sqrt{\frac{R_w}{R_t} + \left(\frac{a \times V_{sh}}{2}\right)^2} - \frac{a \times V_{sh}}{2}\right]$$

Schlumberger Equation:

$$S_w = \frac{\frac{-V_{sh}}{R_{sh}} + \sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{\phi^2}{0.2 \times R_w (1 - V_{sh})}}}{\frac{\phi^2}{0.4 \times R_w (1 - V_{sh})}}$$

...ution: The density-neutron crossplot for this example is shown in Figure 3-70. The shale point ... = 7% and ... = 26%. Resistivity of the adjacent shale bed is R_{sh} = 3.5 ohm-m. Table ... shows the log analysis.

Fertl Equation, where a = 0.25 for Gulf Coast and a = 0.35 for Rocky Mountains:

$$S_w = \frac{1}{\phi} \times \left[\sqrt{\frac{R_w}{R_t} + \left(\frac{a \times V_{sh}}{2}\right)^2} - \frac{a \times V_{sh}}{2}\right] \quad (3.53)$$

Schlumberger Equation:

$$S_w = \frac{\frac{-V_{sh}}{R_{sh}} + \sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{\phi^2}{0.2 \times R_w (1 - V_{sh}) R_t}}}{\frac{\phi^2}{0.4 \times R_w (1 - V_{sh})}} \quad (3.54)$$

Example 3-23. Figure 3-71 shows dual induction focused log, compensated density log, compensated neutron log, and gamma ray log for Codell-Niobrara formation in Weld County, Colorado. Using shaly formation analysis, calculate water saturation for the zone at 6,586–6,598 ft (use Schlumberger Equation). Other data from the log heading are

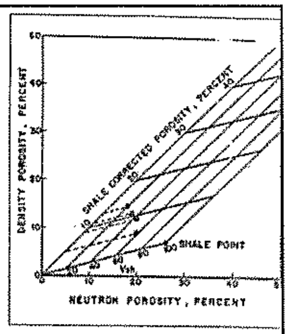


Figure 3-70. Density-neutron crossplot showing shale point, V_{sh} (%), and shale-corrected porosity.

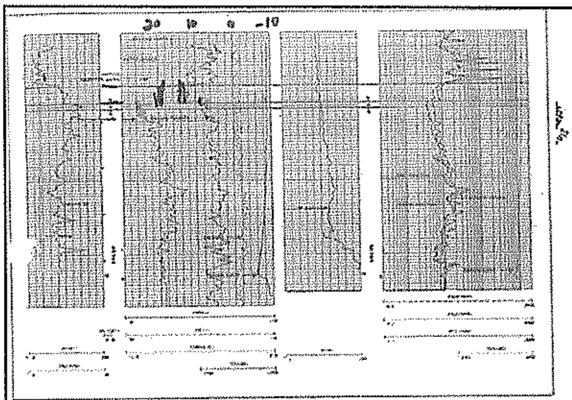


Figure 3-71. Dual induction focused log, compensated density, compensated neutron, and GR log—Codell formation, Weld County, Colorado (courtesy of Miller Oil Co., Ft. Collins, Colorado).

versus true resistivity as affected by a shale group (A_{sh}). The key advantages of the proposed technique

1. The value of m does not have to be assumed; in fact, it can be determined from this analysis by trial and error.
2. Water resistivity does not have to be known in advance provided that the reservoir contains some water-bearing intervals.

TABLE 3–14. Shaly formation evaluation for Example 3–23

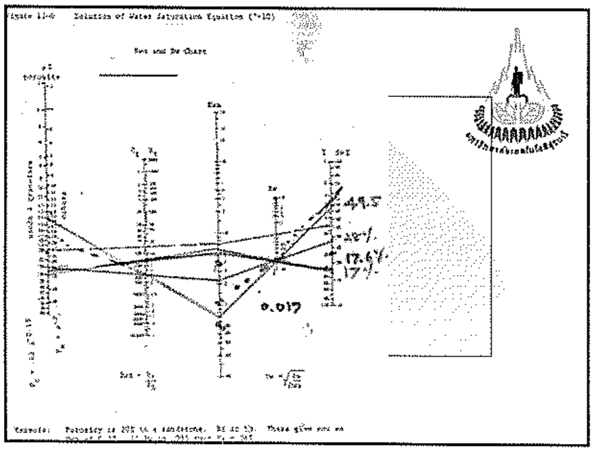
Depth	ϕ_D	ϕ_N	ϕ_{cor}	R_t	V_{sh}	S_w
6,586–6,590 1	0.15	0.18	0.13	7.6	0.20	0.37
6,590–6,594 2	0.12	0.20	0.09	5.6	0.42	0.49
6,594–6,596 3	0.13	0.19	0.11	6.0	0.32	0.43
6,596–6,598 4	0.09	0.20	0.05	5.2	0.59	0.84

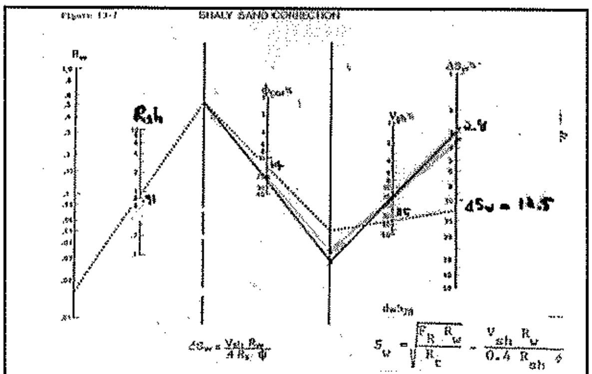
$\phi_{Nsh} = 26\%$

$\phi_{Dsh} = 7\%$

ALGORITHM 3 Shaly Sandstone Interpretation

	Figure #	Equation #
1. Correlate the logs.		
2. Do clean sand analysis as in Algorithm 2 P7-2 Rwa Method		
3. Establish clean and shale line for gamma ray, SP and porosity logs if crossplot to be done.		
4. Establish shale values for resistivity log		
5. Determine volume of shale from:		
Gamma ray	13-1	
SP		13-1
Porosity log crossplot	13-2	13-2,3
6. Use the lowest Vsh from step 4.		
7. Correct the porosity log for shale effects		
density	13-3	13-2
neutron	13-5	13-3
acoustic (if your desperate)	13-4	
If you crossplotted density - neutron and this was the shale volume used -read porosity off of crossplot------otherwise use density porosity.		
8. Determine Rw from nearby clean sand or [illegible]		
9. Calculate Sw	13-6, 13-7	13-4
10. Compare Sw from step 2 to that of step 9. Step 9 should be lower.		





$S_{wc} = S_w - \Delta S_w = \sqrt{\frac{F_R R_w}{R_t}} - \frac{V_{sh} R_w}{0.4 R_{sh} \phi}$

Example 13.1 Shaly S.S. Interpretation

1. Correlate Logs
2. Find R_w in Clean Sand
   @ 10300–10340
   $\phi_D = 27\%$ $\phi_N = 25\%$
   C = 5250 → $R_t = \frac{1000}{5250}$ → 0.19 Ωm
   $R_w = \frac{R_t}{F_r} = \frac{0.19}{\frac{0.62}{0.26^{2.15}}} = 0.017$ Ωm
3. Read Data from log $S_w = \sqrt{\frac{F_R R_w}{R_t}}$

Zone	C	Rt	ϕ_N	ϕ_D	Sw
A	150	6.7	26	26	17
B	350	2.86	24	17	38

4. @ 10190–10200' Shale value, are
   $R_{sh} = 0.91$, $\rho_b = 2.52$ g/cc ($\phi_D = 8\%$)
   $\phi_{Nsh} = 29\%$ ($\phi_{Nsh} = 32\%$)
5. Gamma ray @ Shale base line = 9.2 divisions
   @ A = 3.2
   B = 5.1
   I_{GR} @ A = $\frac{3.2}{8.2}$ = 0.39
   B = $\frac{5.1}{8.2}$ = 0.63
   $I = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$
6. Correct for Vsh.
   Fig 13.5 for Neutron log. Fig 13.3 for Density

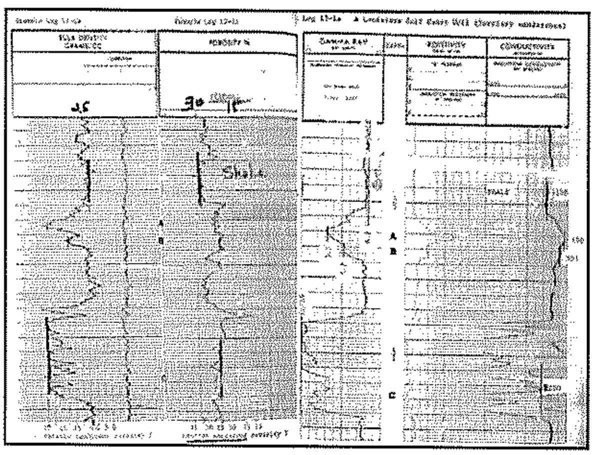
	ϕ_N	ϕ_{NC}	ϕ_D	ϕ_{DC}
A	26	21	26	25
B	24	13	17	

7. Cal. Sw
   Fig 13.6 $S_w - \Delta S_w$ (Fig 13.7)

	Density	Swc	Neutron	Swc
A	17.6 − 2.8 = 14.8%		21.9 − 3.3 = 18.7	
B	49.5 − 12	37.5%	54.4 − 14.1	41.8

Or Crossplot ϕ_N, ϕ_D
$\frac{2\phi_N + 7\phi_D}{9}$
Or → A $\phi_t = 24$
B $\phi_t = 13.8$
A Sw = 18
B Sw = 39.1

$S_w = \frac{-\frac{V_{sh}}{R_{sh}} + \sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{\phi^2}{0.2 \times R_w (1 - V_{sh}) R_t}}}{\frac{\phi^2}{0.4 \times R_w (1 - V_{sh})}}$



Example 13-1 Shaly Sandstone Interpretation

General: The logs (example logs 13-1a, b and c) are over Tertiary sandstones in the Louisiana Gulf Coast. The well was drilled with an oil base mud and thus there is no short normal or SP. The logs are from Dresser Atlas and the neutron log is a sidewall neutron. At the bottom of both the density and neutron a sandstone porosity scale has been put on to ease the calculations.

Simplified Shaly Sand Interpretation

In this technique only the raw data are used with the water saturation being calculated from the induction and neutron and the porosity being determined from the density log.

Rw We will determine Rw from the clean sandstones from 10300 to 10340. The porosity from the density and neutron over this interval are 27% and 25% respectively. We will assume the porosity is 26%. The conductivity of the induction log is about 5250 millimhos/m which is 0.19 ohm m.

$$R_w = \frac{R_t}{F_R} = \frac{.19}{11.2} = .017 \text{ ohm m}$$

We will interpret two zones: A at 10218 - 10224
(induction log depths) B at 10226 - 10234

Data Read from the logs

	conductivity	neutron porosity	density porosity
A	150 (R= 6.7)	26%	26%
B	350 (R=2.86)	24	17

Sw = 17% for zone A and = 28% for zone B (using induction & neutron)

Complete Shaly Sand Interpretation

We will use the Rw from above of .017 ohm m. We will also interpret the same zones and thus can use the same log readings.

1. The density and neutron logs are about two feet deeper than the induction log.
2. The same zones A and B will be used.
3. A R = 6.7 Neutron SS. Porosity = 26% Den. SS. Por. = 26%
   B 2.86 24 17
   As both porosities in zone A are the same this zone will appear to be clean. The cleaner zone at 10300 showed the density 2 porosity units (pu) greater than the neutron which indicates one of the logs is a little off of calibration. In a clean zone the two porosities should agree while in a shaly zone the density porosity should be lower.
4. At 10180-10200 the shale values are:
   Rsh = 0.91 (C = 1100), Density = 2.52 gm/cc (ϕ_{SS} = 8%)
   Neutron LS. porosity = 29% (ϕ_{SS} = 32%)

Example 13-1 (continued)

5. The gamma ray shale baseline is at 8.2 divisions from the left side of the log. The clean sand line is at 0 divisions. GR for A is 3.2 divisions, for B is 5.2 divisions.
6. We will interpret the porosity logs separately and afterwards will go back and use both logs together.
7. From Figure 13-1 I_{GR} = "A" 3.2/8.2 = .39
   "B" 5.2/8.2 = .63

   Vsh = A 15%
   B 35%

   Porosities corrected for shale (neutron Fig. 13-5, density Fig. 13-4)
   A neutron = 21% density = 25%
   B neutron = 13% density = 14%
9. The results of the water saturation calculations will be listed as Sw = Sw (Fig. 13-6) - ΔSw (Fig. 13-7)

	Density Log	Neutron Log
A	14.8% = 17.6-2.8	18% = 21.3 - 3.3
B	37.3% = 49.5-12	41.8% = 54.4 - 12.6

The water saturations are close from both the density and neutron log calculations. In zone B which is very shaly there is a significant difference between the simplified and more complete approach.

Under the number 8 is a crossplot of the density and neutron on a sandstone porosity basis. The disagreement in porosities as noted in step 3 causes the shale volumes and porosities to differ from those using only one porosity log. The agreement is still acceptable.

Example 13-1 (continued)

5. The gamma ray shale baseline is at 8.2 divisions from the left side of the log. The clean sand line is at 0 divisions. GR for A is 3.2 divisions, for B is 5.2 divisions.
6. We will interpret the porosity logs separately and afterwards will go back and use both logs together.
7. From Figure 13-1 I_{GR} = "A" 3.2/8.2 = .39
   "B" 5.2/8.2 = .63

   Vsh = A 15%
   B 35%

   Porosities corrected for shale (neutron Fig. 13-5, density Fig. 13-4)
   A neutron = 21% density = 25%
   B neutron = 13% density = 14%
9. The results of the water saturation calculations will be listed as Sw = Sw (Fig. 13-6) - ΔSw (Fig. 13-7)

	Density Log	Neutron Log
A	14.8% = 17.6-2.8	18% = 21.3 - 3.3
B	37.3% = 49.5-12	41.8% = 54.4 - 12.6

The water saturations are close from both the density and neutron log calculations. In zone B which is very shaly there is a significant difference between the simplified and more complete approach.

A 14.8% = 17.6-2.8 18% = 21.3 - 3.3
B 37.3% = 49.5-12 41.8% = 54.4 - 12.6

The water saturations are close from both the density and neutron log calculations. In zone B which is very shaly there is a significant difference between the simplified and more complete approach.

Under the number 8 is a crossplot of the density and neutron on a sandstone porosity basis. The disagreement in porosities as noted in step 3 causes the shale volumes and porosities to differ from those using only one porosity log. The agreement is still acceptable.

8. Neutron-density crossplot for example 13-1

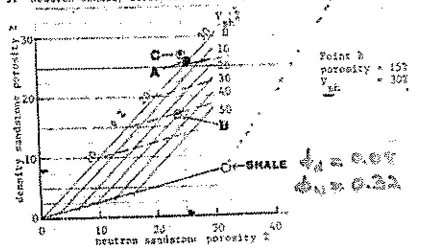
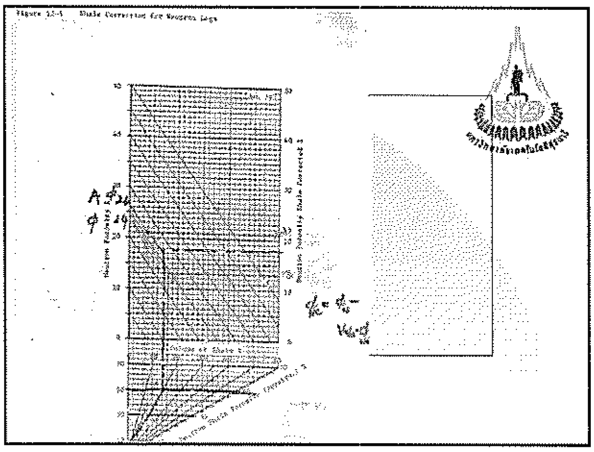
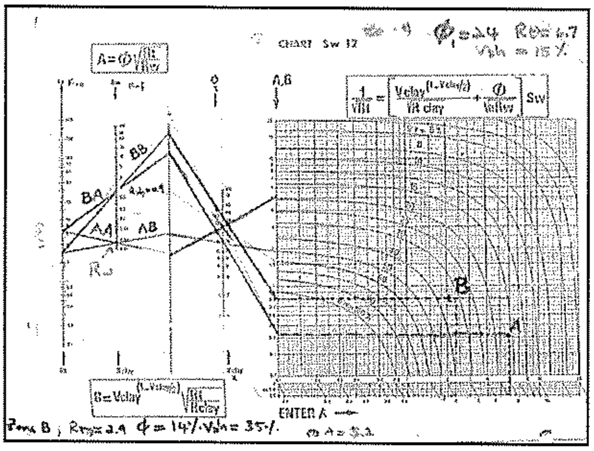


Figure 13-5 Shale Correction for Neutron Logs

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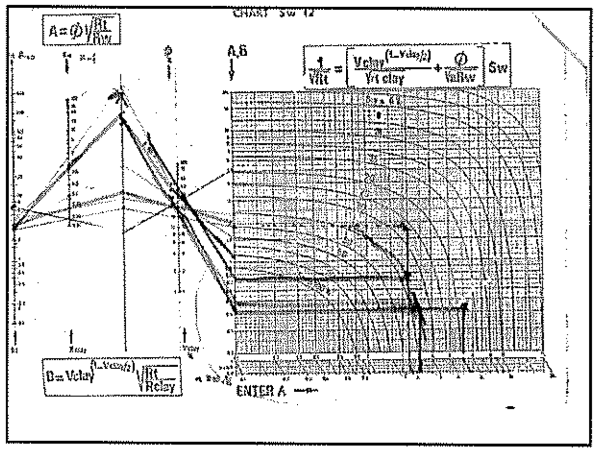
ENTER A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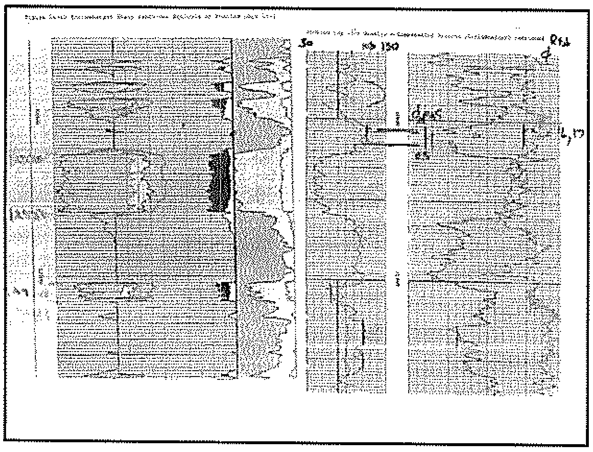
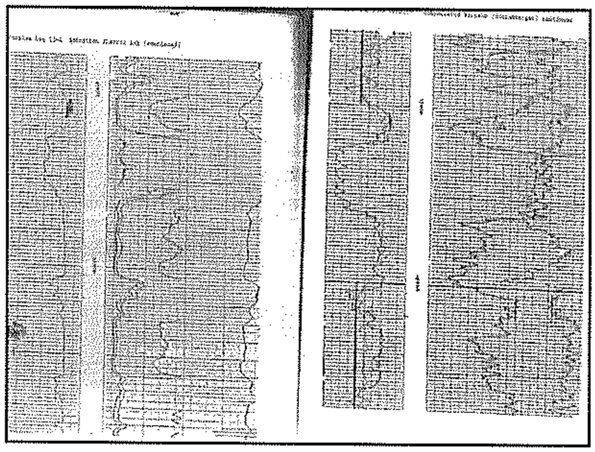
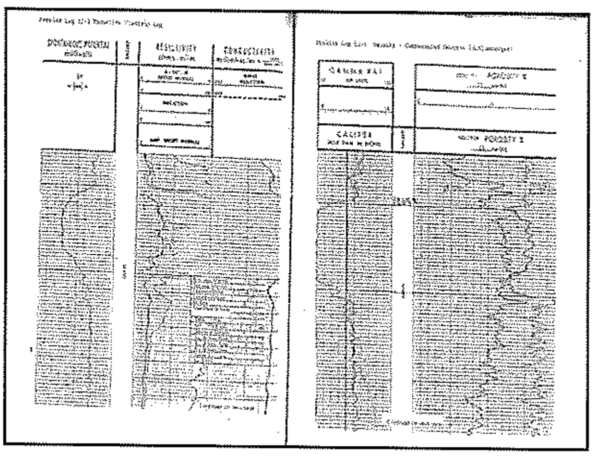
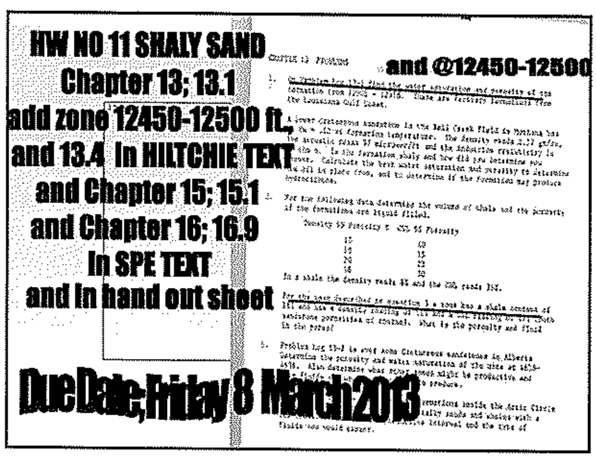
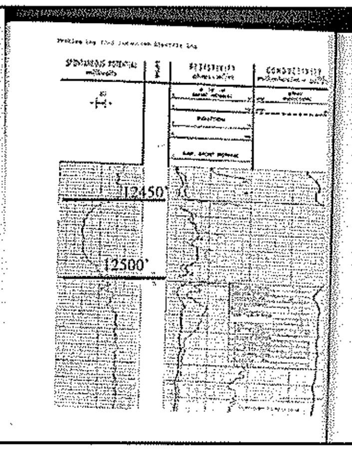







HW NO 11 SHALY SAND
Chapter 13; 13.1
add zone 12450-12500 ft.
and 13.4 In HILTCHIE TEXT
and Chapter 15; 15.1
and Chapter 16; 16.9
In SPE TEXT
and In hand out sheet
and @12450-12500
Due Date; Friday 8 March 2013



Problems

15.1 Examine the IES and density logs of Figs. 15.23 and 15.24, and then answer the following questions. These logs were obtained in a U.S. gulf coast well.

a. Using the gamma ray curve, estimate the shale content of Zone Q.

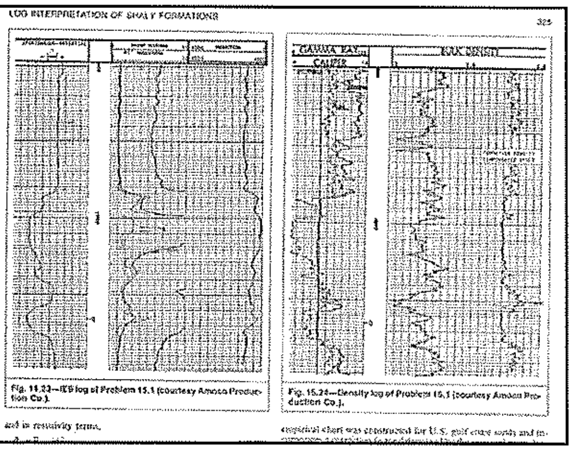
b. Explain why in this case the SP curve cannot be used to estimate shale content.

c. Using density log data, estimate the effective porosity of Zone Q.

d. If $R_w = 0.07\ \Omega \cdot m$ at formation temperature, use the Fertl and Hammack equation to estimate S_w of Zone Q.

Chapter 15

Problem 15.1
a. $V_{sh} = 15\%$.
b. The SP response in the clean sand is affected by the relatively high formation resistivity.
c. $\phi = 27\%$.
d. $S_w = 29\%$.



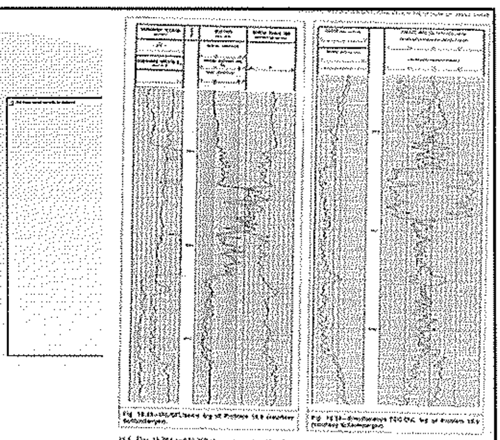
16.9 The DIL/SFL/sonic and FDC/CNL logs of Figs. 16.33 and 16.34 show a thick sand between 5,468 and 5,726 ft. Considering the response of the different tools, the sand can be divided into five major intervals.

Interval A—5,468 to 5,494 ft.
Interval B—5,494 to 5,531 ft.
Interval C—5,535 to 5,588 ft.
Interval D—5,590 to 5,632 ft.
Interval E—5,632 to 5,726 ft.

Identify the fluid type in each interval. Select and determine the porosity and fluid saturation in several zones within each interval. Log heading lists the following information.

Location	Gulf of Mexico
Total depth	7,180 ft
Bit size	12¼ in.
Mud type	Ligno
Mud density	13.0 lbm/gal
R_m	0.79 Ω·m at 78°F
R_{mf}	0.32 Ω·m at 78°F
Maximum recorded temperature	140°F

Problem 16.9 Intervals A through C are gas-bearing; Interval D is oil-bearing; and Interval E is water-bearing.



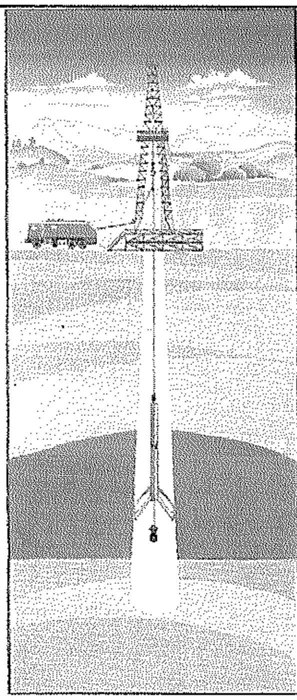


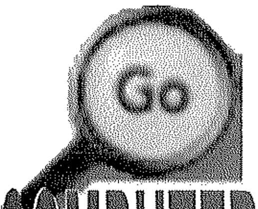
Fig. 1-2—Wireline logging operation.

WELLLOGGING

CHAPTER14
CHAPTER15
CHAPTER16

INTRODUCTIONS & ROCK PROPERTIES(2 hrs.)
Resistivity and Basic Relationships of Well Log Interpretation(1 hrs.)
Resistivity Device(2 hrs.)
Spontaneous Potential (SP) Log(2 hrs.)
Induction Electric and Dual Induction Logs(2 hrs.)
Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1
Abnormal Pressure(1 hr.)
Fracture Detection with Well Logs(1
Dipmeter Principles(2 hrs.)

CHAPTER14



COMPUTER PROCESSING OF WELL LOGS

Ch. 14) Computer Processing of well Logs

Cyberlooks (Cyber Service Unit)(CSU)

1. CORIBAND

   Mixed + Complex lithology

2. SARABAND

   SILT-SHALE-SAND

   SHALY SAND

4. VOLAN — CARBONATE

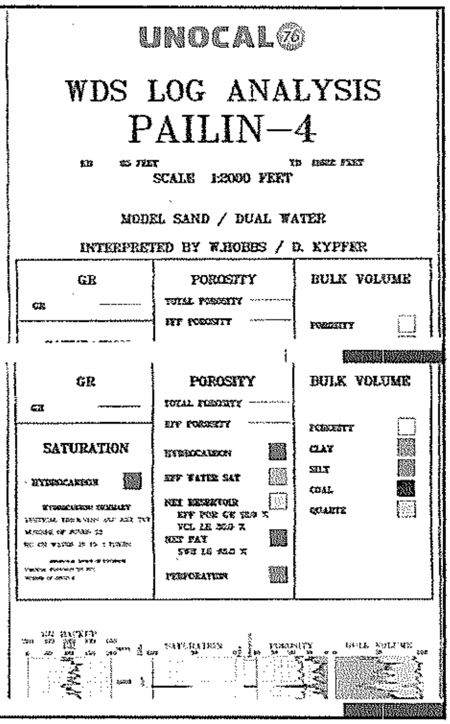
3. DUAL WATER MODELS

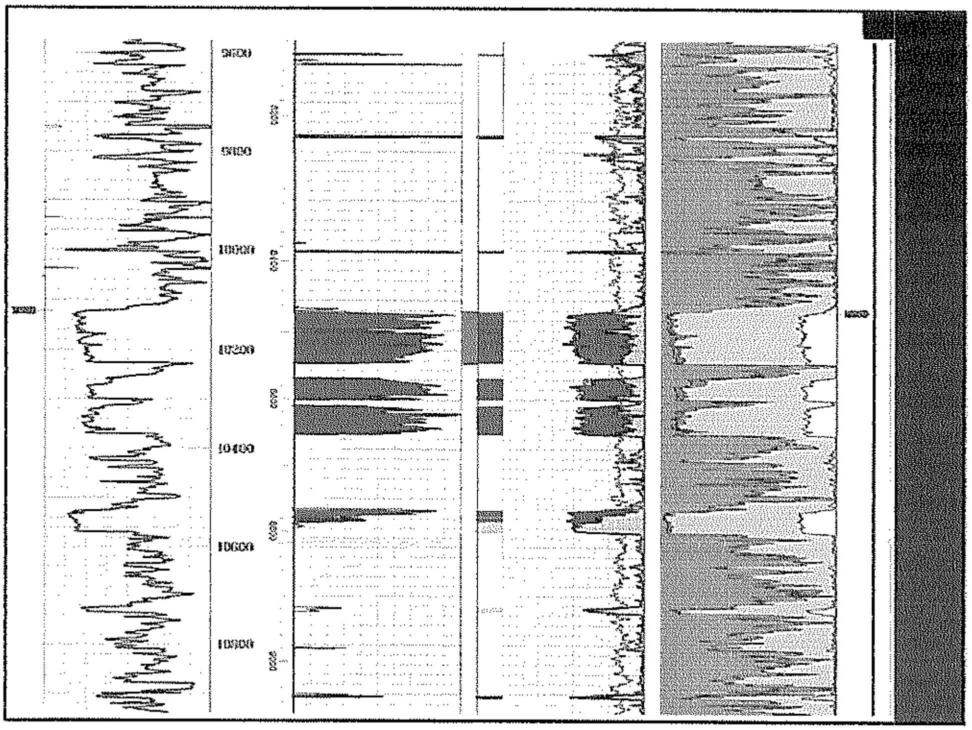
SHALY SAND ANALYSIS

$$\frac{1}{R_t} = \frac{S_w^2}{F^* R_w} + \frac{B Q_v S_w}{F^*}$$

F= Formation factor, B - Sodium Clay-Exchange Cations Conductance

Qv = CEC cation Exchange Capacity

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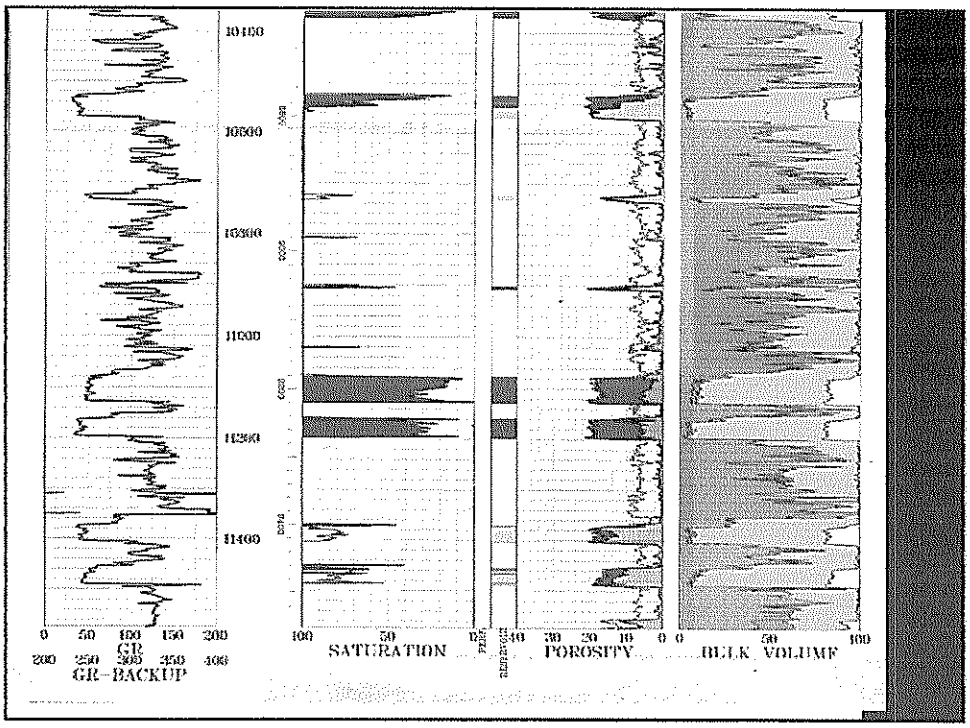
10000
10200
10400
10600
10800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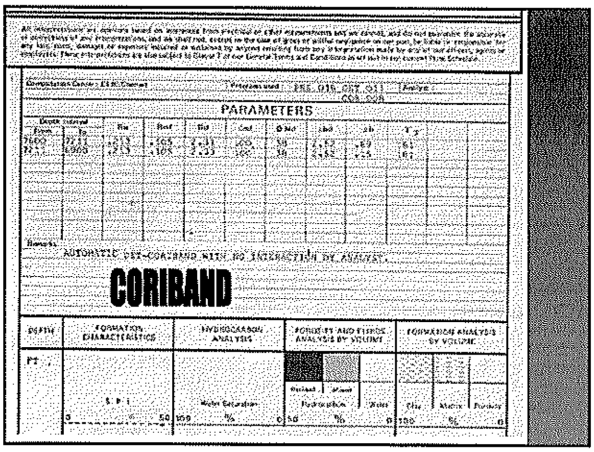
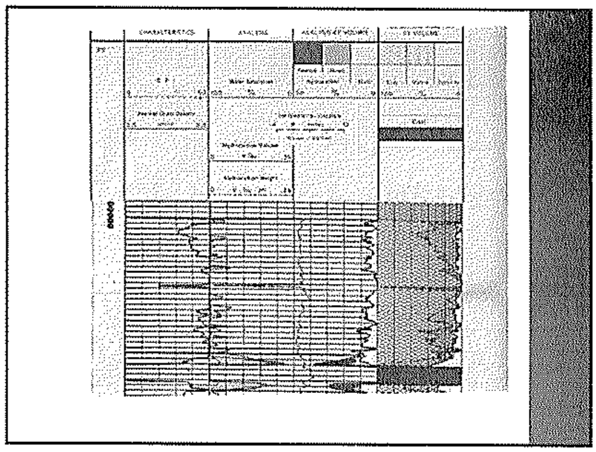
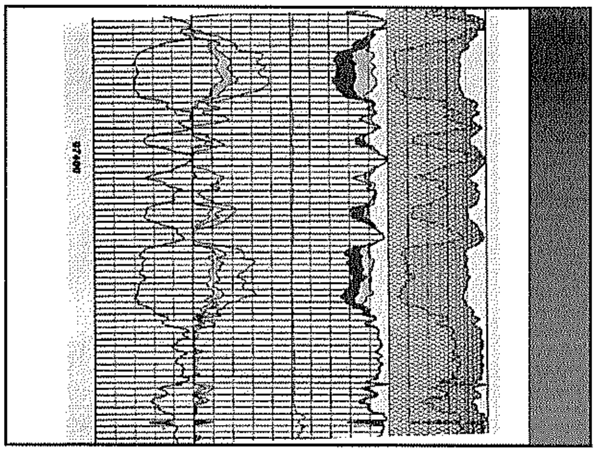
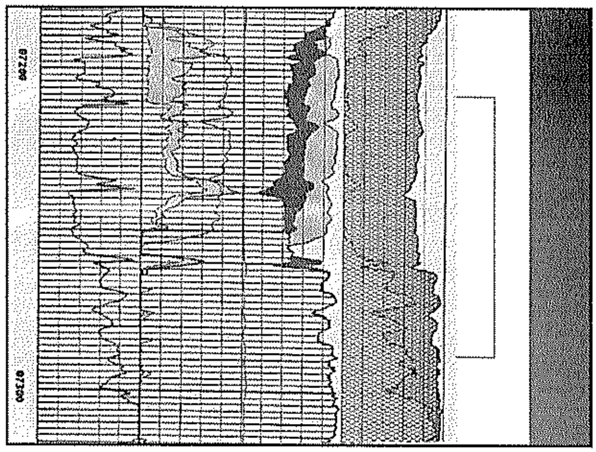
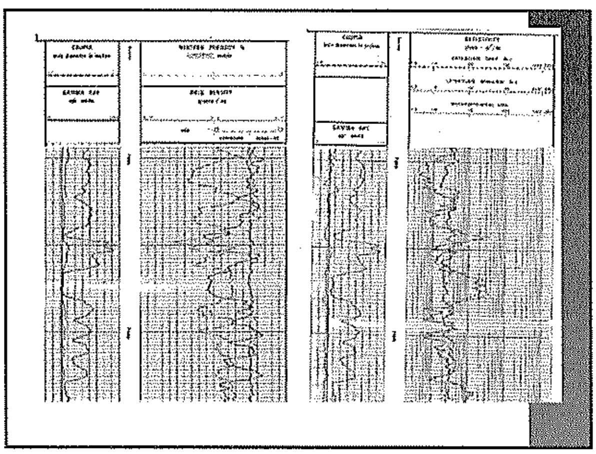
10600
10800
11000
11200
11400
0 50 100 150 200
GR
200 250 300 350 400
GR-BACKUP
100 50 0
SATURATION
40 30 20 10 0
POROSITY
0 50 100
BULK VOLUME

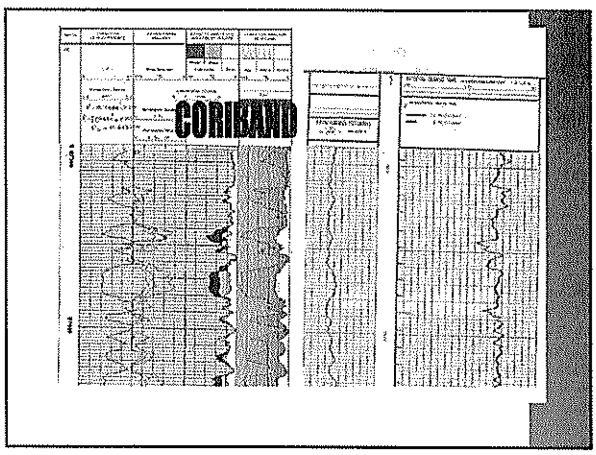

PARAMETERS
CORIBAND

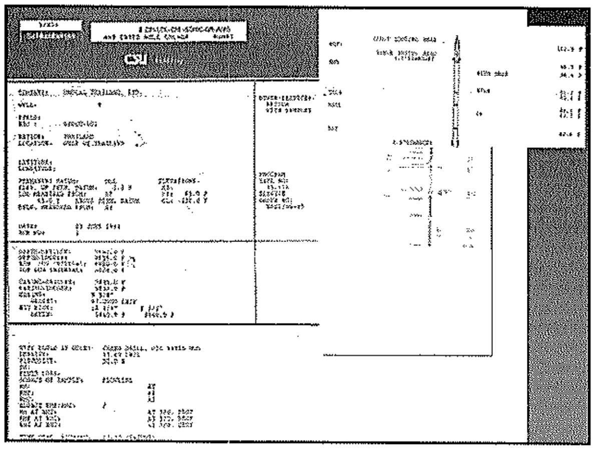


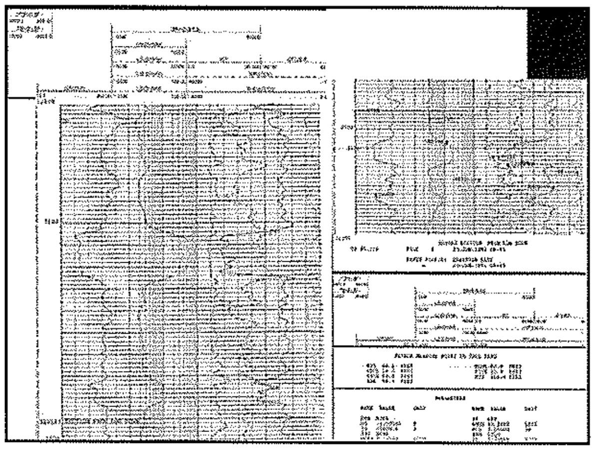


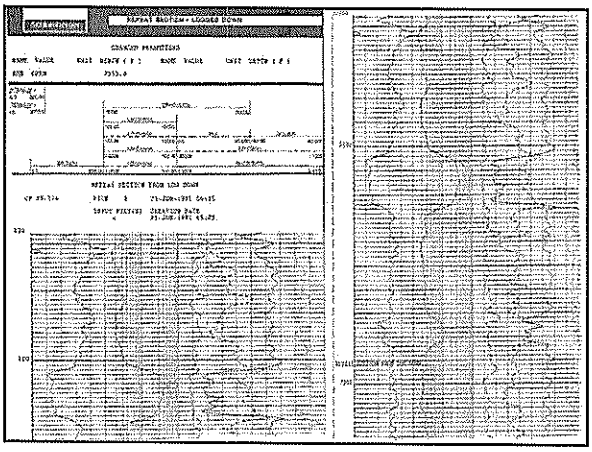


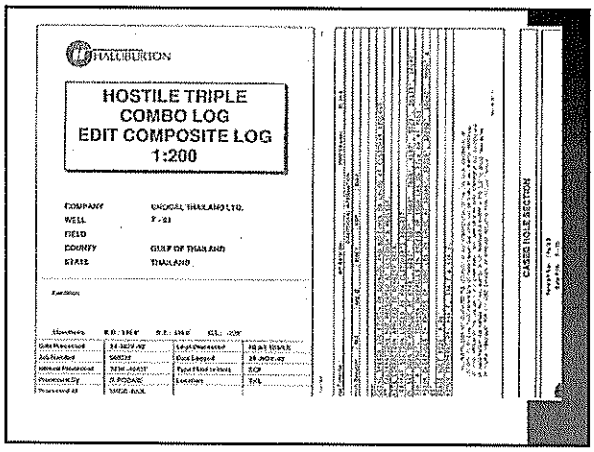


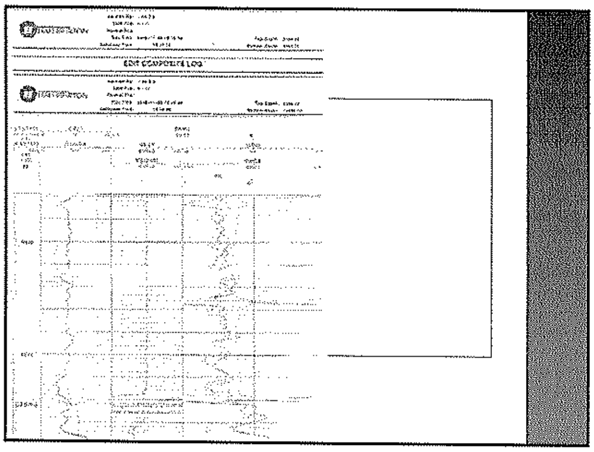

CORIBAND

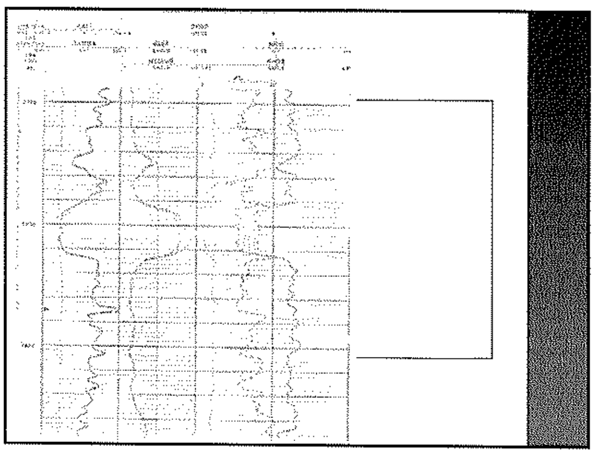


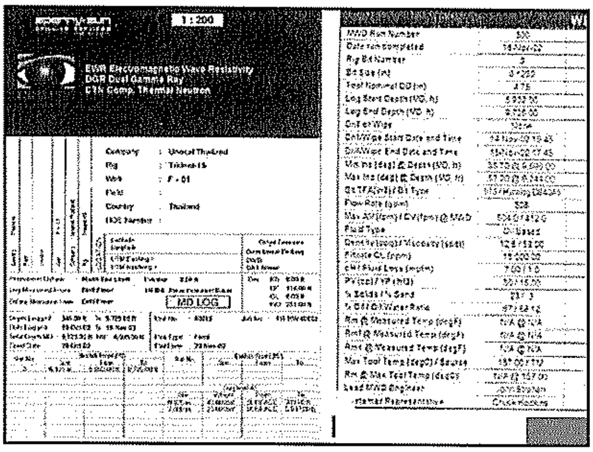


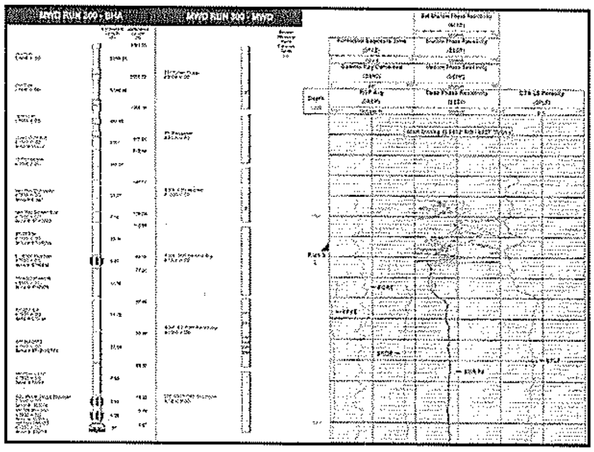


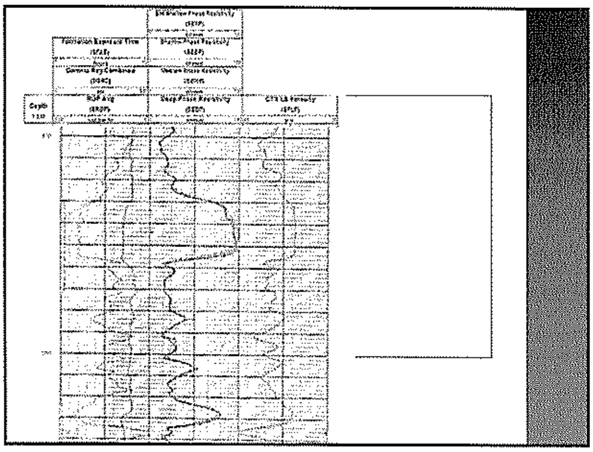

HALLIBURTON
HOSTILE TRIPLE
COMBO LOG
EDIT COMPOSITE LOG
1:200
COMPANY
WELL
FIELD
COUNTY
STATE
GULF OF THAILAND
THAILAND
CASED HOLE SECTION

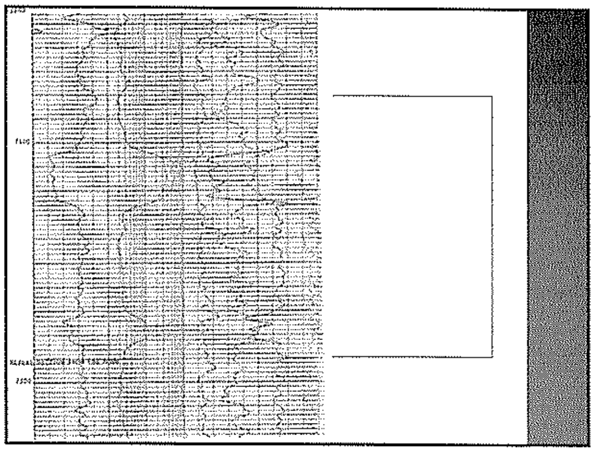

EDIT COMPOSITE LOG




1 : 200
EWR Electromagnetic Wave Resistivity
DGR Dual Gamma Ray
CTN Comp. Thermal Neutron
Company : Unocal Thailand
Country : Thailand
MD LOG


MWD RUN 300 - BHA
MWD RUN 300 - MWD

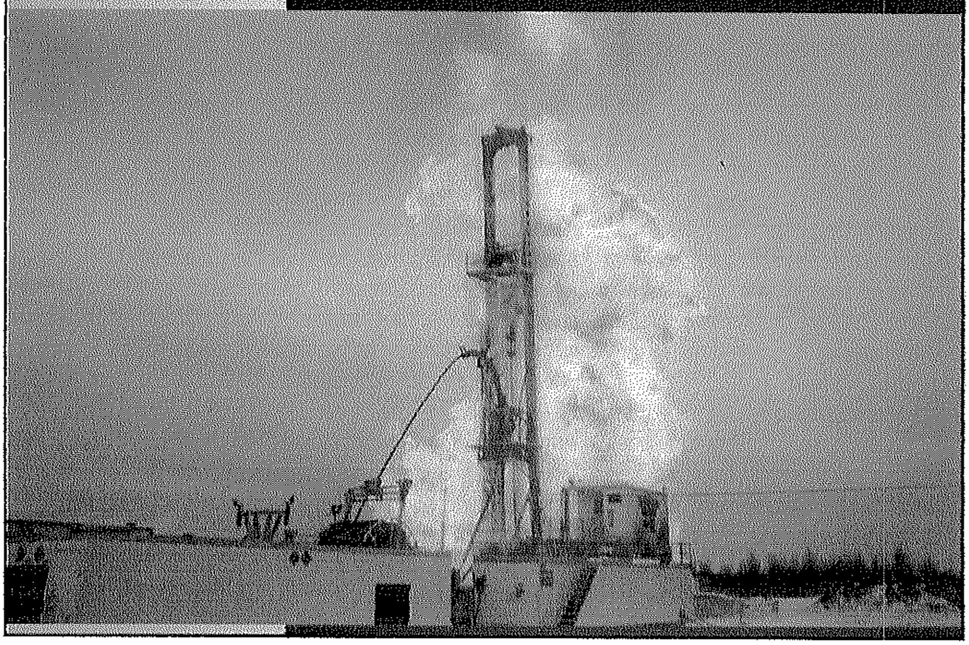




CHAPTER15

ABNORMAL PRESSURE DETECTIONS

GEOPRESSURE



Chapter 15 Abnormal Pressure

> 0.433 to 0.465

Drilling Engineer Mud wt., Blowout risk, Lost circulation

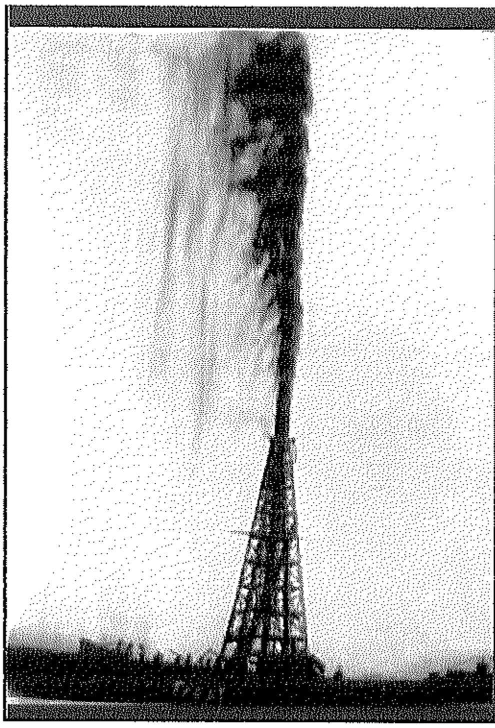
Evaluationist ↑P, Limited Reservoir

Origins

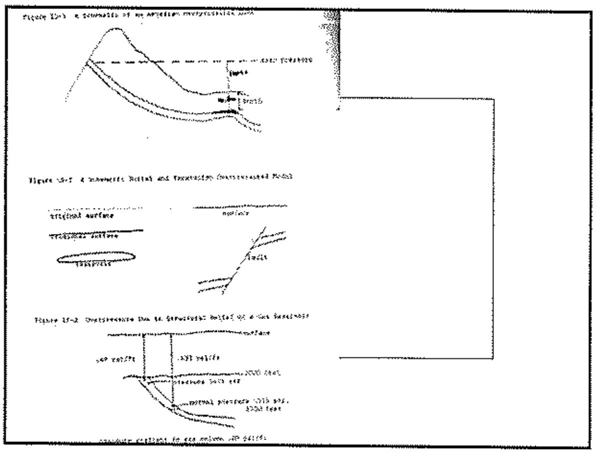
1. Artesian Type
2. Burial and Excavation
3. Large Structural Relief (GAS)
4. Excessive Rapid Deposit
   sealed → liquid can not migrate
5a. Uncompacted, ϕ↑, density↓

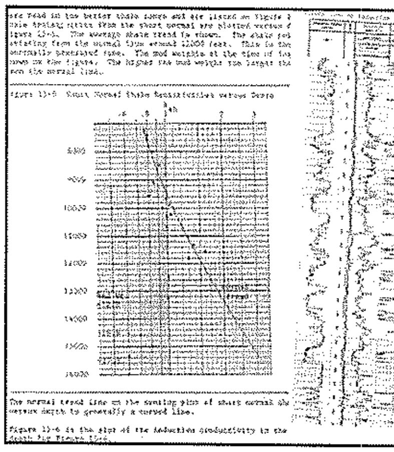
Detecting

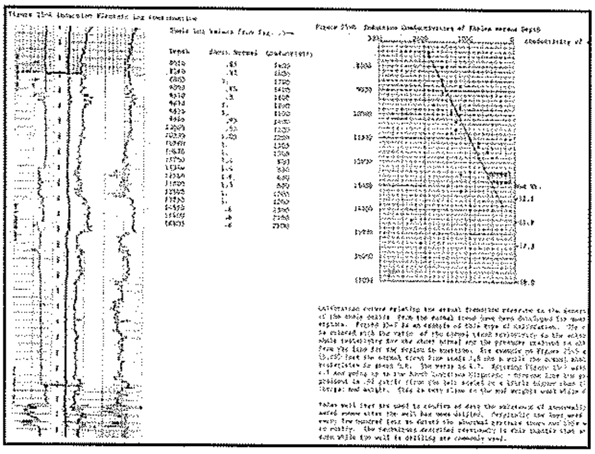
1. Seismic change in acoustic Impedance
   - Low velocity
   - High Impedance
2. Drilling
   - Mud gain
   - Drilling Break high ROP
   - Shale Cutting-density ↓ρ_{sh}
   - Flow Line Temperature T_f↑
3. WELL LOGGINGS
   - Resistivity R_{tsh} ↓ ปกติเพิ่มตาม Depth
   - Acoustic time Δt_{sh} ↑ ปกติลดลงตาม Depth
   - Density ρ_{ma} ↓ ปกติมากขึ้นตาม Depth



Subsurface Pressure







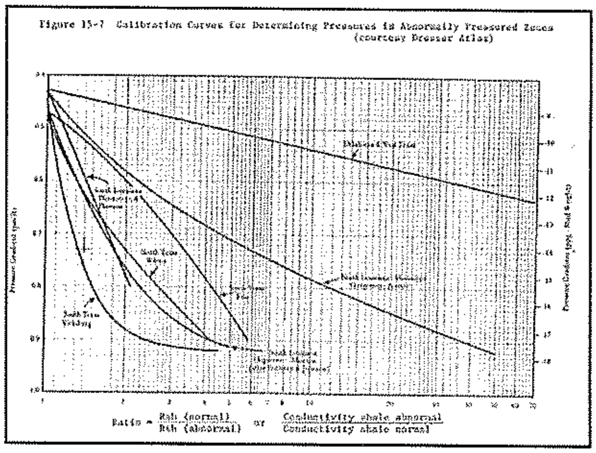


Figure 15-7 Calibration Curves for Determining Pressures in Abnormally Pressured Zones (courtesy Dresser Atlas)

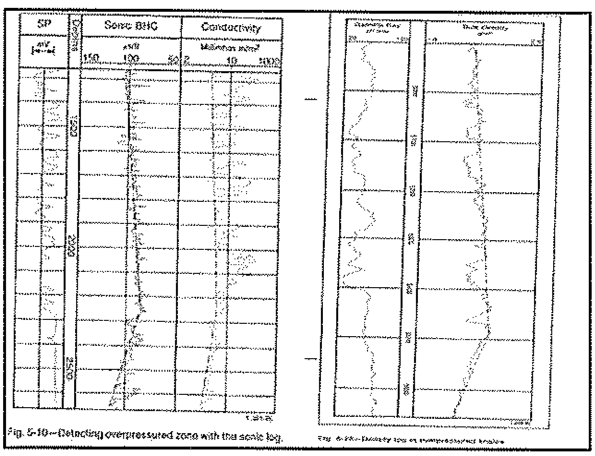
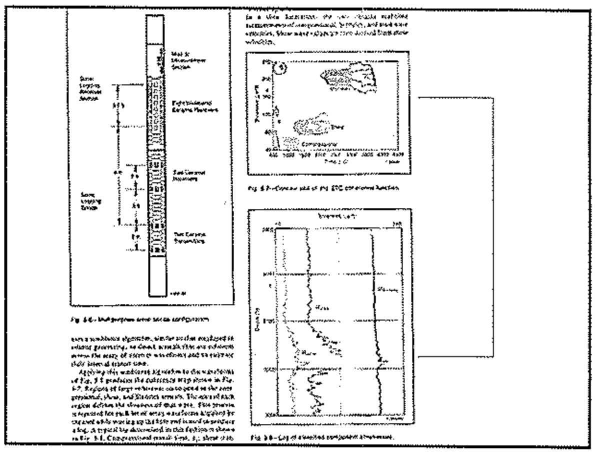
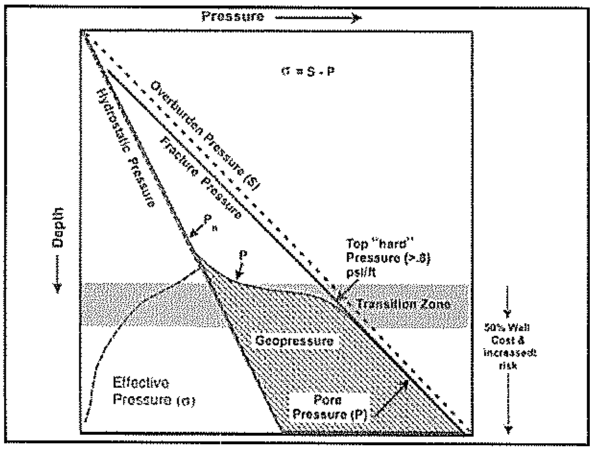
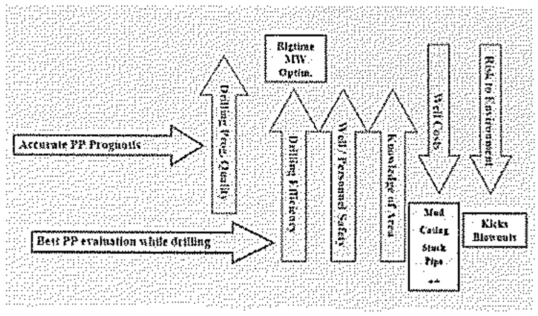


Fig. 5-10—Detecting overpressured zone with the sonic log.





Motivations for Understanding Geo-pressures



Definitions

Normal pressure (hydrostatic pressure or normal fluid pressure) is the pressure exerted by a static column of water of the same height as the overlying pore fluids and the same density as the pore water.

Normal pressure = pressure gradient of water ≈ depth

Pore pressure (fluid pressure or formation pressure) is the pressure exerted by the pore fluids. Units: psi/ft ≈ 19.268 = ppg (pounds per gallon); ppg ≈ 0.0519 = psi/ft; g/cm^3 ≈ 0.433 = psi/ft.

Pore pressure = normal pressure + over/underpressure

Definitions

Overpressure (geopressure) is the excess pressure above normal pressure.

Overpressure = pore pressure ≈ normal pressure

Overburden pressure (lithostatic pressure or geostatic pressure) is the pressure exerted by the overlying pore fluid and rocks.

Overburden pressure = overburden gradient ≈ depth

Terzaghi's relationship (net differential stress or net overburden stress or net confining stress) states that the total stress is jointly supported by the pore fluid and the rock matrix.

S = overburden pressure = pore pressure + effective pressure = P + χ

Definitions

Effective vertical stress is the stress applied to the rock matrix.

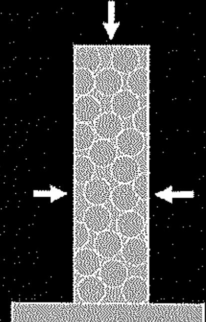
Effective pressure (χ) = overburden pressure ≈ pore pressure = S ≈ P

Buoyant pressure is the excess pressure created in confined reservoir by the density difference between hydrocarbons and water

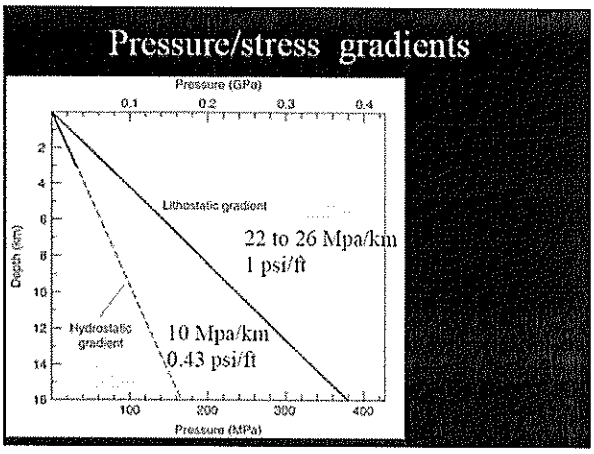
ΔP = (water gradient ≈ hydrocarbon gradient) ≈ height of hydrocarbon column

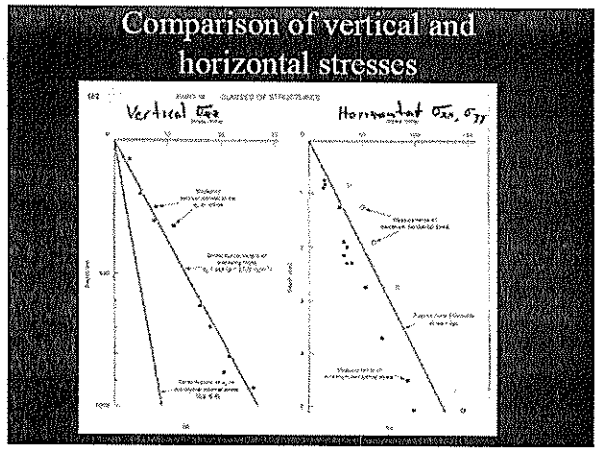
Pore pressure = normal pressure + overpressure (brine-filled) + buoyancy pressure.

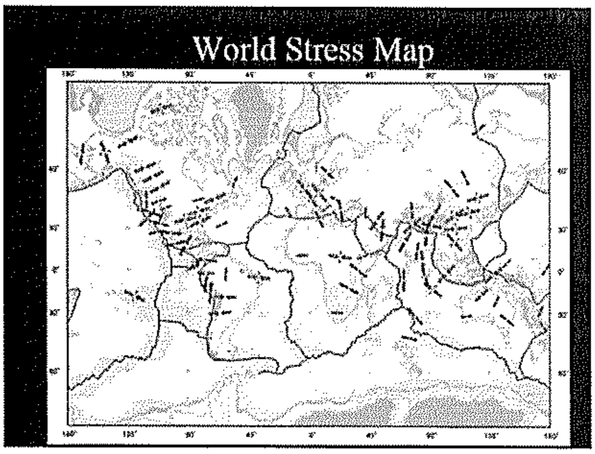
Lithostatic stress/ hydrostatic stress

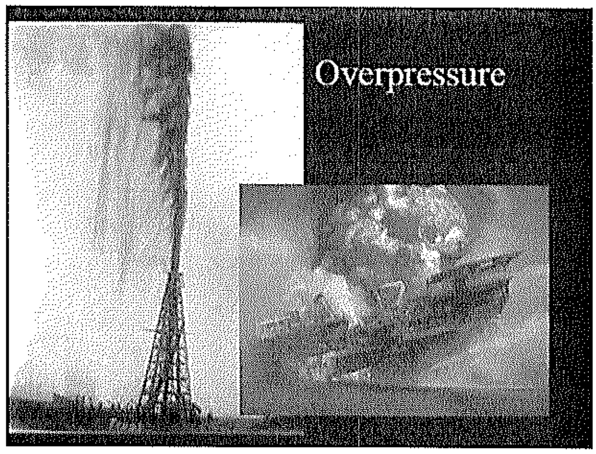


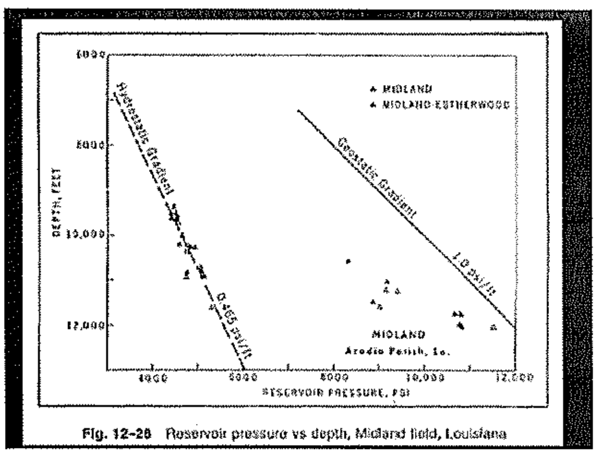
- Lithostatic stress
- Tectonic stress
- Fluid Pressure
  - -Hydrostatic
  - -Hydrodynamic

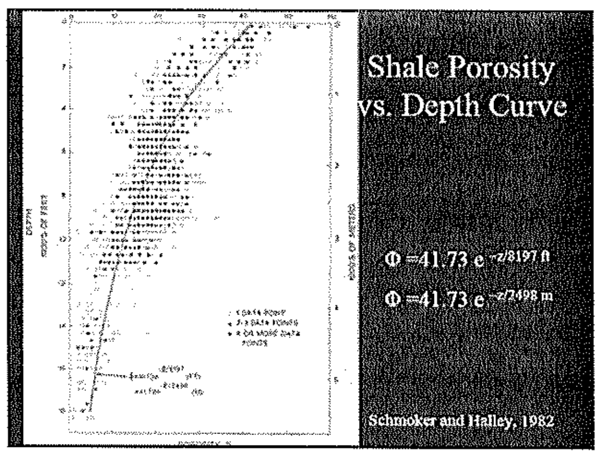

Pressure/stress gradients
Pressure (GPa)
0.1
0.2
0.3
0.4
Lithostatic gradient
22 to 26 Mpa/km
1 psi/ft
Hydrostatic gradient
10 Mpa/km
0.43 psi/ft
Depth (km)
100
200
300
400
Pressure (MPa)

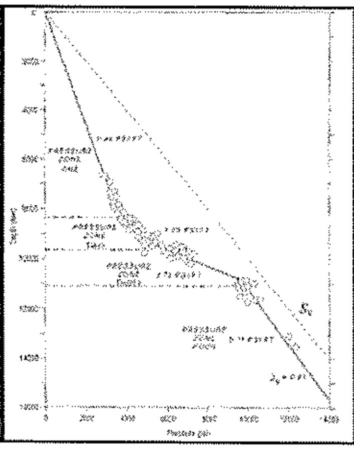

Comparison of vertical and horizontal stresses
Vertical
Horizontal


World Stress Map


Overpressure


MIDLAND
MIDLAND ESTHERWOOD
Hydrostatic Gradient
Geostatic Gradient
1.0 psi/ft
0.465 psi/ft
DEPTH, FEET
MIDLAND
Acadia Parish, La.
RESERVOIR PRESSURE, PSI
Fig. 12-28 Reservoir pressure vs depth, Midland field, Louisiana

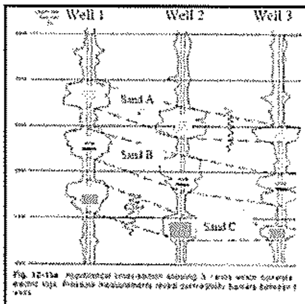

Shale Porosity vs. Depth Curve
Φ =41.73 e $^{-z/8197 ft}$
Φ =41.73 e $^{-z/2498 m}$
Schmoker and Halley, 1982

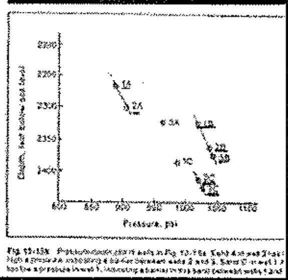


Pore pressure in the Monte Cristo Field (Texas)

Engelder and Leftwich, 1997

Reservoir Compartments

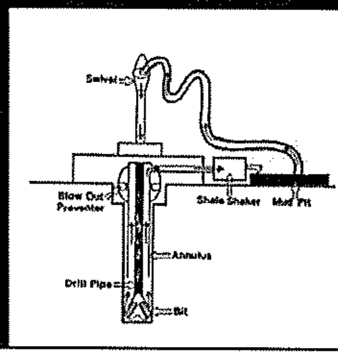




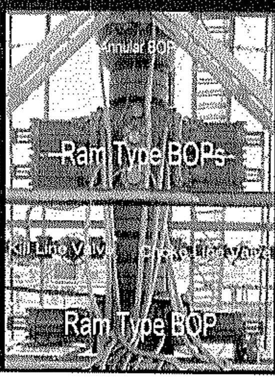
Characteristics of Overpressure Zones

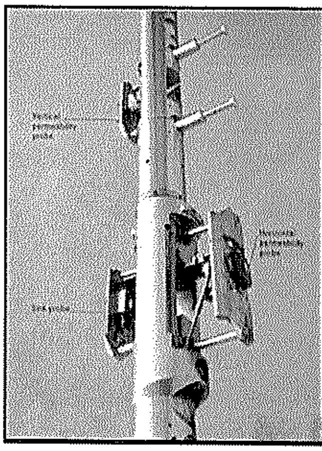
- Under-compacted shale
- Low density, low sonic velocity
- Rapid Drilling Rate
- Low Thermal Conductivy, high T
- Low Salinity

Controlling Reservoir Pressure



Blow Out Preventers





Formation Tester Schlumberger

Drill Stem Test

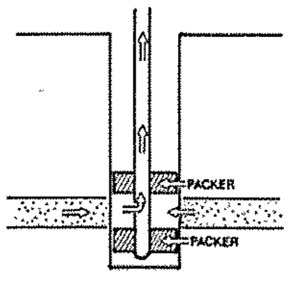
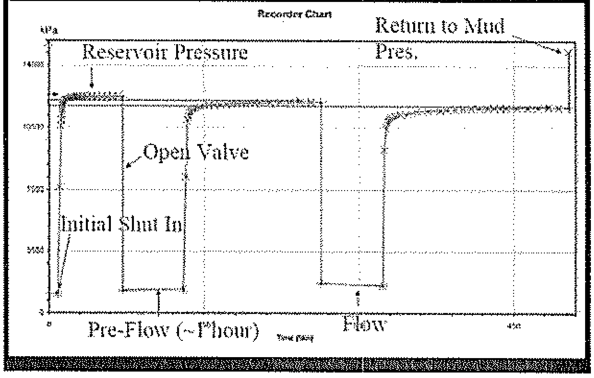
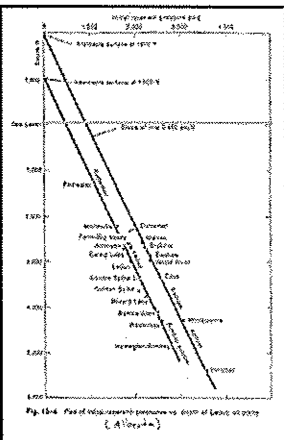


Figure 18-2 A drill stem test.

Drill Stem Test Pressure Results

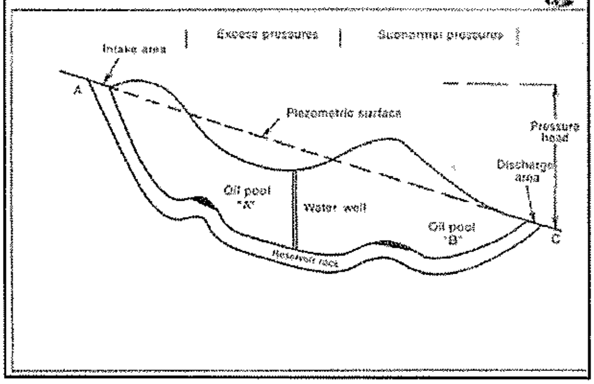


Initial Reservoir Pressure Leduc Fields, Alberta (Canada)



Leduc #1 Gas flare

Hydrodynamic System



SUBSURFACE PRESSURES 373

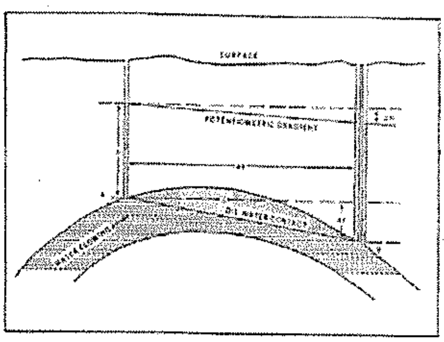
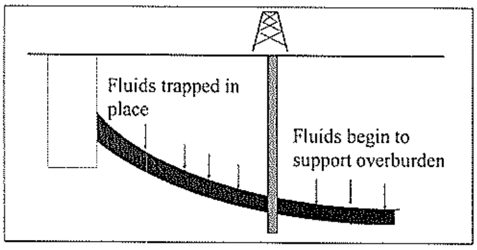


Fig. 12-20 Diagram showing why a flow results in a tilting of the oil-water contact. (From Hubbert)

Abnormal Formation Pressures

- Due to:
  - Incomplete compaction
  - Diagenesis
  - Differential Density in Dipping Formations
  - Fluid Migration
  - Tectonic Movement
  - Aquifers
  - Thermal Effects

Incomplete compaction



Diagenesis

- At 200°F to 300°F Clays undergo chemical alteration. Montmorillonite clays dehydrate and release some of the bound water into the space already occupied by free water, increasing pressure

Differential Density in Dipping Formations

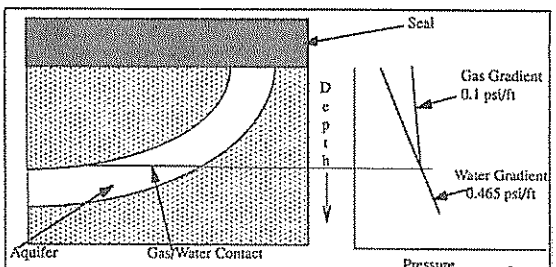


Figure 9.1 - The low hydrostatic gradient of a long gas column will result in abnormally high pressure at the top of the formation.

Fluid Migration

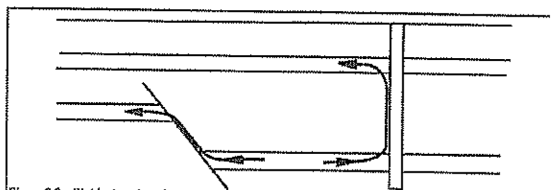


Figure 9.2 - Fluid migration along a fault plane or a poor cement job results in abnormally pressured formations

Tectonic Movement - Uplifting

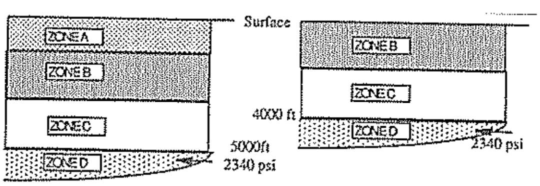


Figure 9.3 - Uplifting and erosion results in abnormal pressure due to the shorter column of mud available to balance formation

Tectonic Movement - Faulting

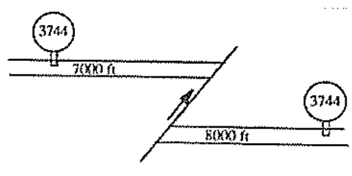


Figure 9.4 - The uplifting of one fault block can result in abnormal pressure.

Aquifers

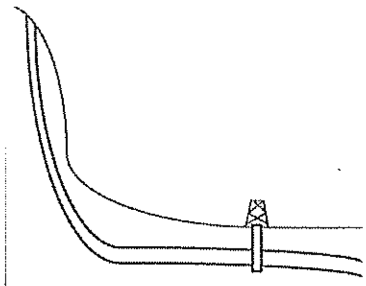
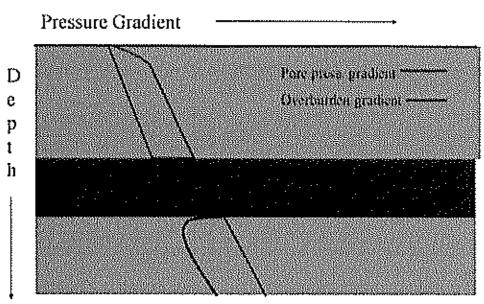


Figure 9.5 - The extreme height of an aquifer outcropping in the mountains results in abnormal pressure from a well drilled in a valley

Thermal Effects

- Theories
  - Increased temperature with depth and chemical reactions cause increased pressures
  - Increased pressures caused increased temperatures

Salt Formations



Shale Properties used to Predict Pore Pressures

- Shales are used because:
  - Most pressure transition zones occur in relatively thick shales
  - Properties of clean shales are fairly homogeneous at any depth, and can be predicted with some degree of accuracy.

Shale Properties used to Predict Pore Pressures

- Shales are used because:
  - A deviation from the expected can be interpreted as a change in pressure gradient
  - Detecting these deviations in low permeability shales gives an early warning prior to drilling into pressured permeable formations, thus avoiding kicks.

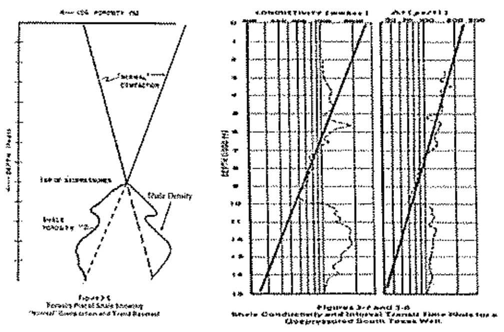
Normally Pressured Shales

- Porosity - Decreases with depth
- Density - Increases with depth
- Conductivity - Decreases with depth
- Resistivity - Increases with depth
- Sonic travel time - Decreases with depth
- Temp. gradient - Relatively constant

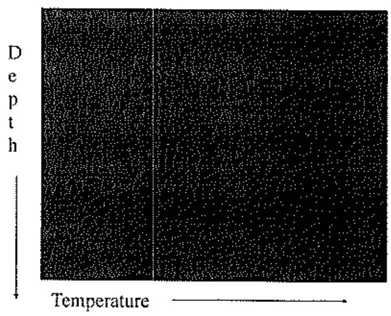
Abnormally Pressured Shales

- Porosity - Higher than expected
- Density - Lower than expected
- Conductivity - Higher than expected
- Resistivity - Lower than expected
- Sonic travel time - Higher than expected
- Temp gradient - Increases

Porosity Density Conductivity Sonic



Temperature gradient - Increases



Pore Pressure Prediction Occurs:

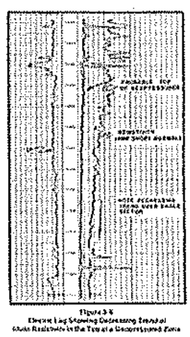
- Prior to drilling
- During drilling
- After drilling

Before Drilling

- Offset mud records, drilling reports, bit records, well tests
- Geological Correlation

Before Drilling

- Open Hole Logs from offset wells



Before Drilling

- Seismic data

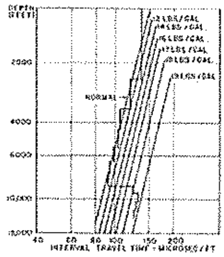


Figure 3-9
Evaluation of Abnormal Pressure from Seismic Data
(After Pennebaker)

Indications of Abnormal Pore Pressures

Methods:

1. Seismic data
2. Drilling rate
3. Sloughing shale
4. Gas units in mud
5. Shale density
6. Chloride content

Indications of Abnormal Pore Pressures

Methods, cont'd:

7. Change in Mud properties
8. Temperature of Mud Returns
9. Bentonite content in shale
10. Paleo information
11. Wire-line logs
12. MWD-LWD

Prediction and Detection of Abnormal Pressure Zones

1. **Before drilling**
   - Shallow seismic surveys
   - Deep seismic surveys
   - Comparison with nearby wells

Prediction and Detection of Abnormal Pressure Zones

2. While drilling
   - Drilling rate, gas in mud, etc. etc.
   - D - Exponent
   - D_C - Exponent
   - MWD - LWD
   - Density of shale (cuttings)

Prediction and Detection of Abnormal Pressure Zones

3. After drilling
   - Resistivity log
   - Conductivity log
   - Sonic log
   - Density log

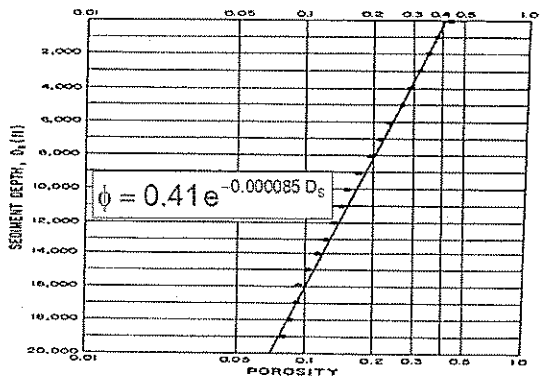


Fig. 6.4—Computed average porosity trend for U.S. gulf coast area.

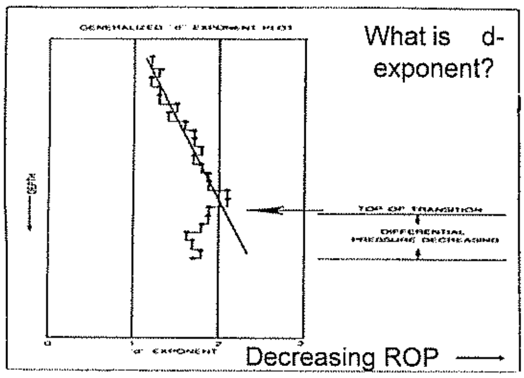


Fig. 6-26 Generalized "d" exponent plot

D - Exponent

The drilling rate equation:

$$R = KN^E\left(\frac{W}{D_B}\right)^D$$

Where
- R = drilling rate, ft/hr
- K = drillability constant
- N = rotary speed, RPM
- E = rotary speed expon.
- W = bit weight, lbs
- D_B = bit diameter, in
- D = bit wt. Exponent or D - exponent

D - Exponent

$$R = KN^E\left(\frac{W}{D_B}\right)^D$$

If we assume that K = 1 and E = 1

Then

$$\frac{R}{N} = \left(\frac{W}{D_B}\right)^D \Rightarrow D = \frac{\log\left(\frac{R}{N}\right)}{\log\left(\frac{W}{D_B}\right)}$$

D - Exponent

A modified version of this equation follows:

$$d = \frac{\log\left(\frac{R}{60\ N}\right)}{\log\left(\frac{12\ W}{10^6\ D_B}\right)}$$

Example

d may be Corrected for mud density as follows:

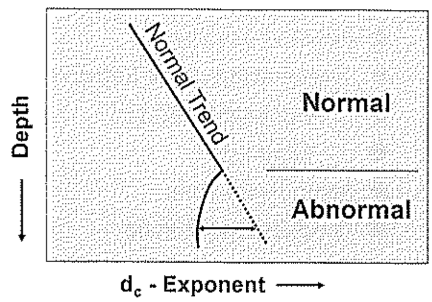
$$d_c = d\left(\frac{\text{mud weight for normal gradient (ppg)}}{\text{actual mud weight in use(ppg)}}\right)$$

$$\text{e.g., } d_c = d\left(\frac{9}{12}\right) = 1.82 * \left(\frac{9}{12}\right) = 1.37$$

Procedure for Determining Pore Pressure From d_c - Exponent

- Calculate d_c over 10-30 ft intervals
- Plot d_c vs depth (use only date from **Clean shale sections**)
- Determine the normal line for the d_c vs. depth plot.
- Establish where d_c deviates from the normal line to determine abnormal pressure zone

Procedure for Determining Pore Pressure From d_c - Exponent

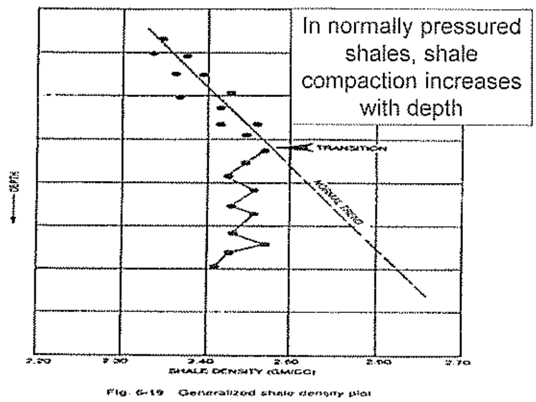


Procedure for Determining Pore Pressure From d_c - Exponent

- If possible, quantify the magnitude of the abnormal pore pressure using **overlays, or Ben Eaton's Method**

$$\frac{P}{D}=\frac{S}{D}-\left(\frac{S}{D}-\left(\frac{P}{D}\right)_n\right)\left(\frac{d_c \text{ calculated}}{d_c \text{ normal}}\right)^{1.2}$$

Pore Pressure Grad. — Overburden Stress Grad. — **Normal Pore Pressure Grad.**

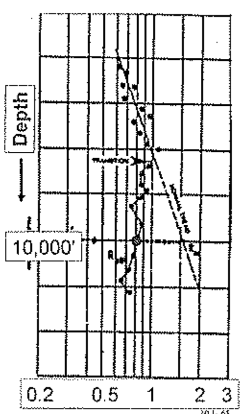


Pore Pressure from Resistivity

Shale resistivity plots may be developed from (i) logs or (ii) cuttings

What is the pore pressure at the point indicated on the plot?

[Assume Gulf Coast]. Depth=10,000 ft



EATON

From plot, $R_n = 1.55$ ohms

$R_{obs} = 0.80$ ohms

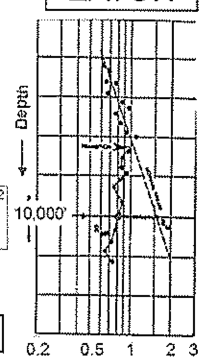
From Eaton:

$$\frac{P}{D}=\frac{S}{D}-\left(\frac{S}{D}-\left(\frac{P}{D}\right)_n\right)\left(\frac{R_{obs}}{R_n}\right)^{1.2}$$

$$\frac{P}{D}=0.95-(0.95-0.465)\left(\frac{0.80}{1.55}\right)^{1.2}$$

= 0.7307 psi/ft = 14.05 lb/gal

P = 0.7307 * 10,000 = 7,307 psi



Prediction of Abnormal Pore Pressure

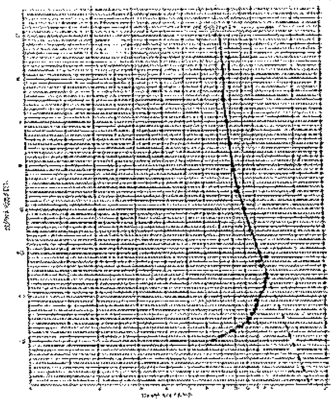
- Resistivity of Shale
- Temperature in the Return Mud
- Drilling Rate Increase
- d_c - Exponent
- Sonic Travel Time
- Conductivity of Shale

EXAMPLE

Shale Resistivity vs. Depth

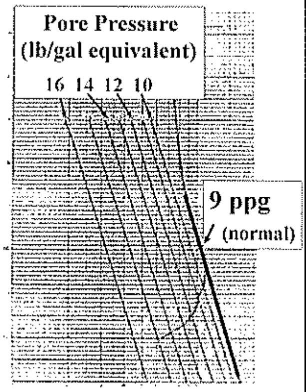
1. Establish normal trend line
2. Look for deviations

(semi-log)

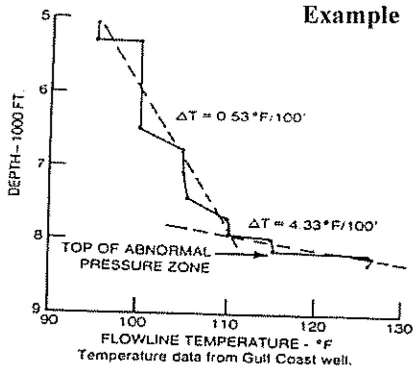


Shale Resistivity vs. Depth

1. Establish normal trend line
2. Look for deviations
3. Use OVERLAY to quantify pore pressure (use with caution)



Example



Temperature data from Gulf Coast well.

8.2 X

Why?

Determination of Abnormal Pore Pressure Using the d_c - exponent

From Ben Eaton:

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left(\frac{d_c}{d_{cn}}\right)^{1.2}$$

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left(\frac{d_c}{d_{cn}}\right)^{1.2}$$

Where $\frac{P}{D}$ = formation pressure gradient, psi/ft

$\left(\frac{P}{D}\right)_n$ = normal water gradient in area e.g., 0.433 or 0.465, psi/ft

$\frac{S}{D}$ = overburden stress gradient, psi/ft

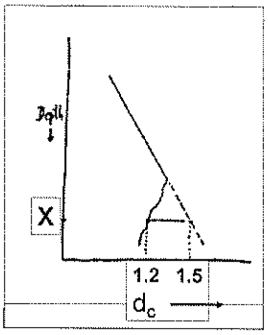
d_c = actual d_c – exponent from plot

d_{cn} = d_c – exponent from the normal trend

Example

Calculate the pore pressure at depth X using the data in this graph.

Assume:
West Texas location with normal overburden of 1.0 psi/ft.
X = 12,000 ft.



Example

From Ben Eaton:

$$\frac{P}{D}=\frac{S}{D}-\left[\frac{S}{D}-\left(\frac{P}{D}\right)_n\right]\left(\frac{d_c}{d_{cn}}\right)^{1.2}$$

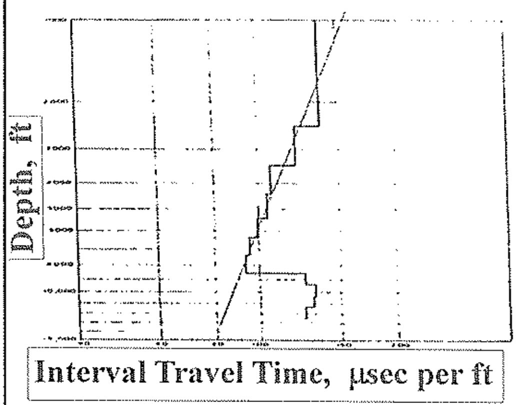
$$=1.0-[1.0-0.433]\left(\frac{1.2}{1.5}\right)^{1.2}$$

$$\frac{P}{D}=0.5662\ \text{psi/ft}$$

Example

$$\therefore P = 0.5662 \times 12{,}000 = 6794\ \text{psi}$$

$$\text{EMW} = \frac{6794}{0.052 \times 12{,}000} = 10.9\ \text{lbm/gal}$$



Ben Eaton

also found a way to determine pore pressure from interval travel times.

Example:
In a Gulf Coast well, the speed of sound is 10,000 ft/sec at a depth of 13,500 ft. The normal speed of sound at this depth, based on extrapolated trends, would be 12,000 ft/sec. What is the pore pressure at this depth?

Assume: S/D = 1.0 psi/ft

Ben Eaton

From Ben Eaton,

$$\frac{P}{D}=\frac{S}{D}-\left[\frac{S}{D}-\left(\frac{P}{D}\right)_n\right]\left(\frac{\Delta t_n}{\Delta t}\right)^{3.0}$$

$$=1.0-[1.0-0.465]\left(\frac{10{,}000}{12{,}000}\right)^{3}$$

$$=\underline{0.6904\ \text{psi/ft}} \qquad (\Delta t \propto 1/v)$$

Ben Eaton

From Ben Eaton

$\rho = (0.6904 / 0.052) = \mathbf{13.28\ lb/gal}$

$p = 0.6904 * 13{,}500 = \mathbf{9{,}320\ psig}$

Note: Exponent is 3.0 this time, NOT 1.2!

Equations for Pore Pressure Determination

$$d_c = \frac{\log\left(\frac{R}{60N}\right)}{\log\left(\frac{12W}{10^6 D_B}\right)} * \left(\frac{\rho_{NORMAL}}{\rho_{ACTUAL}}\right)$$

$$\frac{P}{D} = \frac{S}{D} - \left(\frac{S}{D} - \left(\frac{P}{D}\right)_n\right)\left(\frac{d_c \text{ calculated}}{d_c \text{ normal}}\right)^{1.2}$$

$$\frac{P}{D} = \frac{S}{D} - \left(\frac{S}{D} - \left(\frac{P}{D}\right)_n\right)\left(\frac{R_{obs}}{R_n}\right)^{1.2}$$

$$\frac{P}{D} = \frac{S}{D} - \left(\frac{S}{D} - \left(\frac{P}{D}\right)_n\right)\left(\frac{C_n}{C_o}\right)^{1.2}$$

$$\frac{P}{D} = \frac{S}{D} - \left(\frac{S}{D} - \left(\frac{P}{D}\right)_n\right)\left(\frac{\Delta t_n}{\Delta t_o}\right)^{3.0}$$

Pore Pressure Determination

$\frac{P}{D}$ = Formation pressure gradient, either normal or geopressured, psi/ft

$\left(\frac{P}{D}\right)_N$ = Normal water gradient in the area, e.g. 0.433 or 0.465, psi/ft

$\frac{S}{D}$ = Overburden stress gradient, psi/ft

R_o = Shale resistivity from well log, ohm-meters

R_N = Shale resistivity from normal line, ohm-meters

C_o = Shale conductivity from well log, millimhos/meter

Δt_o = Shale travel time value, microseconds/ft

etc.

CHAPTER16

FRACTURE DETECTIONS

CHAPTER16

FRACTURE DETECTIONS

Chapter 16. Fracture Detection

1. Core Analysis
2. Logging
   - Variable Density Log (VDL)
     suddenly change in sonic wave. (WaveTrain)
   - Long-spaced Sonic (LSS)
   - Array-Sonic
   - Fracture Identification Log
     (FIL dipmeter Microresistivity measurement)

ensity and neutron log detection of fractures

ensity and neutron logs generally do not see fractures conclusively. The .5 to 1.5% porosity increase is almost impossible to see on these logs unless the matrix porosity is very low and constant. Once in a while if the formation is badly fractured these logs will show an abnormally high porosity due to the "streaming" of the gamma rays and neutrons up the fracture. This streaming phenomena has been noticed in surface to pits. The density log correction curve will sometimes pick up a fracture as an increase in correction. In any of these cases the identification is not conclusive.

Resistivity log detection of fractures

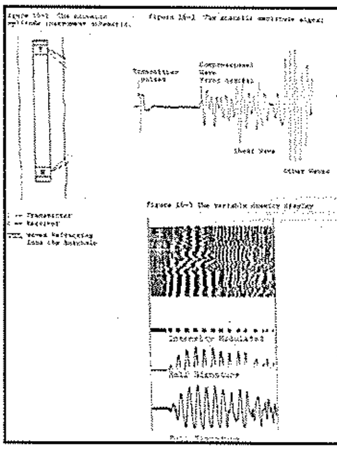
The resistivity of a rock is greatly reduced when the current flow is parallel to the fracture. If the current flow is perpendicular to the fracture the effects are negligible. When selecting a resistivity log to detect fractures one must select the log that will do the job properly. The use of induction logs to detect fractures is poor as the current flows around the borehole (in the formation) and does not flow parallel to the fracture for more than a very short distance. Laterolog and micro-focused resistivity logs are most influenced by fractures. Some caution must be used when using resistivity logs to detect fractures. The mud system can play an important role in this problem. An open fracture will generally be filled with mud filtrate. If the mud is fresh and the formation is basically impermeable (not invaded) Table shows that you may not be able to see the resistivity reduction. If the mud is a salt system you will be able to see the fracture.

Table 16-1 The effect of fractures (idealized) on resistivity

Porosity %	Resistivity (approximate)		
	no fracture	fracture filled formation water	fracture filled mud filtrate
5	8	0.5	5
10	2	0.3	3
15	0.9	0.2	2

Rw = .02 Rmf = .2 all calculations approximate

In a fracture system with a dual induction laterolog run over it, the



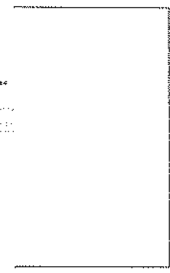
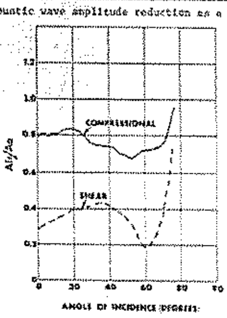


Figure 16-4 Acoustic wave amplitude reduction as a function of fracture dip



*Urzhan, I. P., Elastic Wave Propagation in Fractured and Vuggy Media, IZV Earth Physics, No. 10, 1970

Figure 16-5 Fracture finding with an acoustic amplitude and travel time log (courtesy Welex)

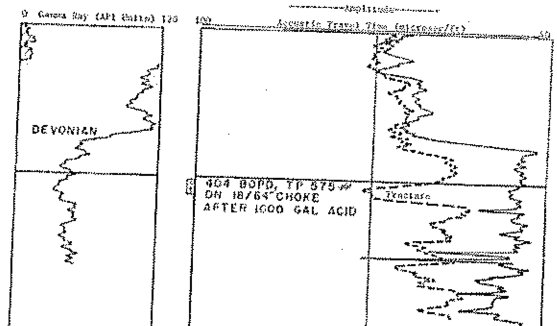
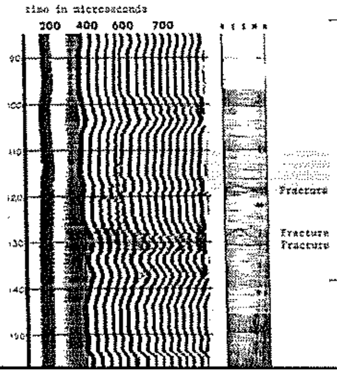
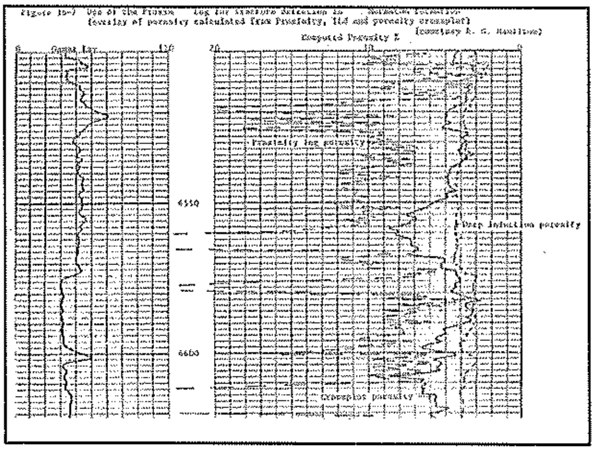


Figure 16-6 Variable density display and Borehole Televiewer (BHTV) showing fractures over a Chattanooga limestone section (courtesy Birdwell)





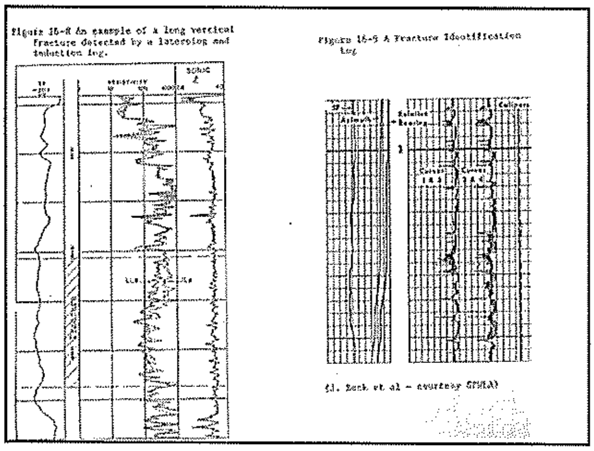
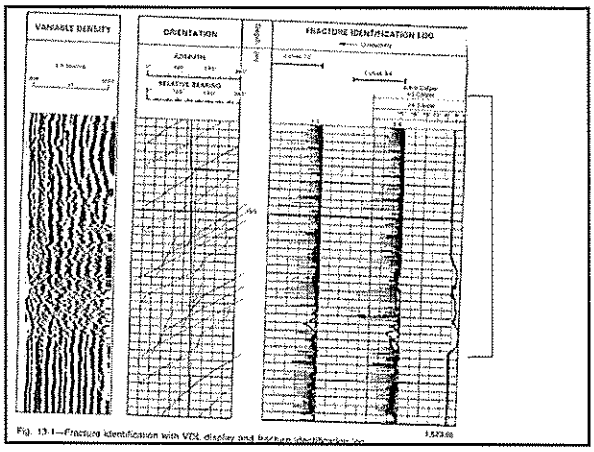
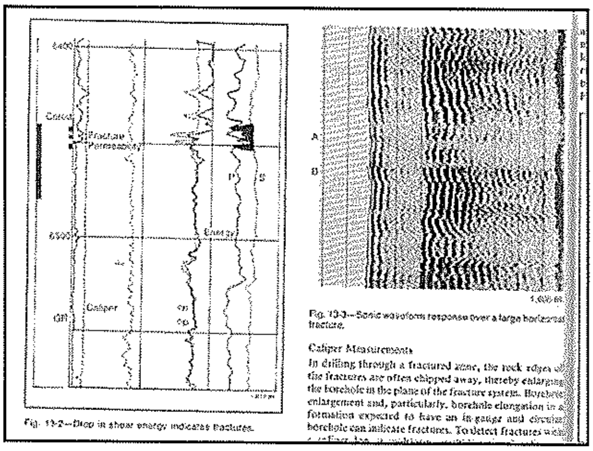
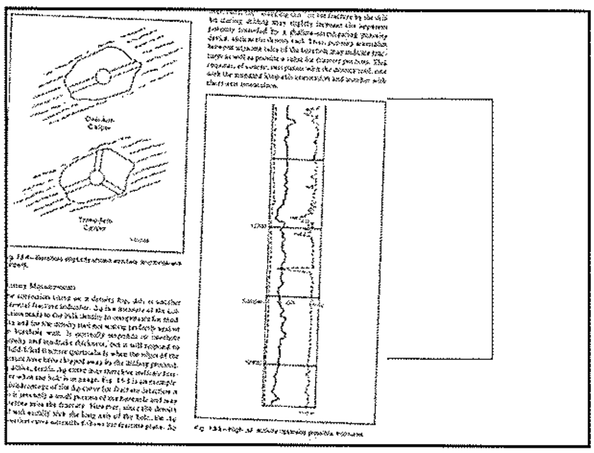
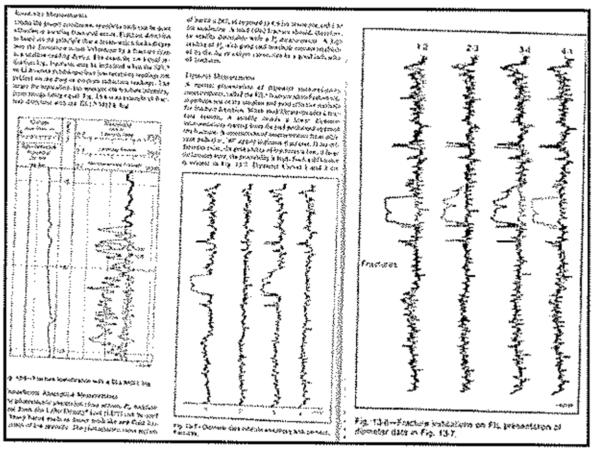


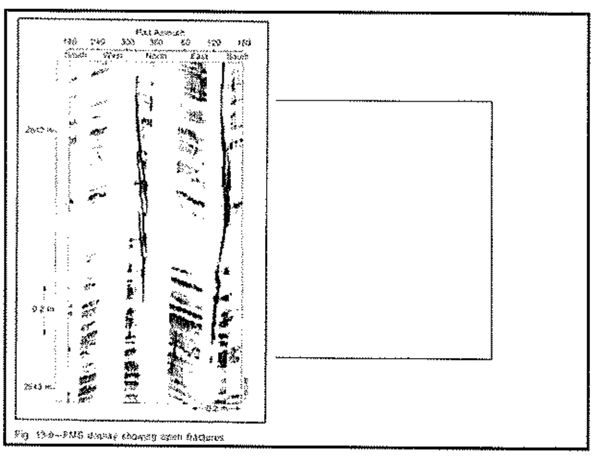
Figure 16-8 An example of a long vertical fracture detected by a laterolog and induction log.
Figure 16-9 A Fracture Identification Log
(J. Beck et al - courtesy SPWLA)

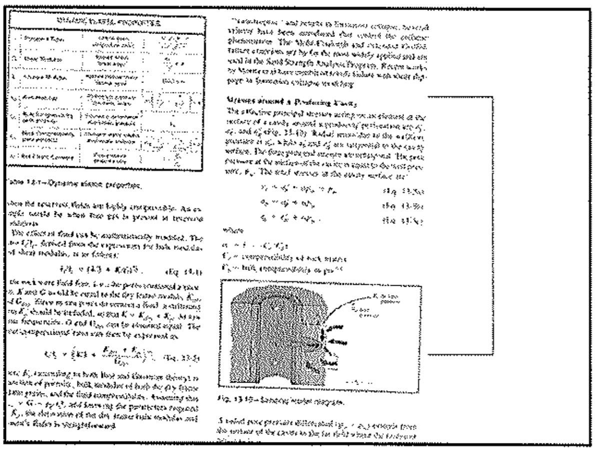

VARIABLE DENSITY
ORIENTATION
FRACTURE IDENTIFICATION LOG
Fig. 13-1—Fracture identification with VDL display and fracture identification log

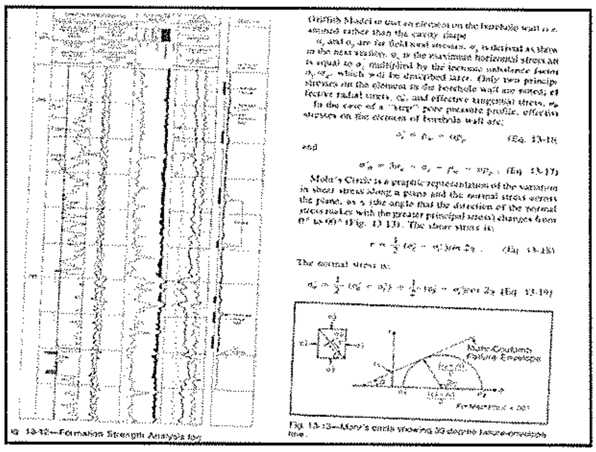

Fracture
Caliper
Fig. 13-2—Drop in shear energy indicates fractures.
Fig. 13-3—Sonic waveform response over a large horizontal fracture.
Caliper Measurements
In drilling through a fractured zone, the rock edges of the fractures are often chipped away, thereby enlarging the borehole in the plane of the fracture system. Borehole enlargement and, particularly, borehole elongation in a formation expected to have an in-gauge and circular borehole can indicate fractures. To detect fractures with

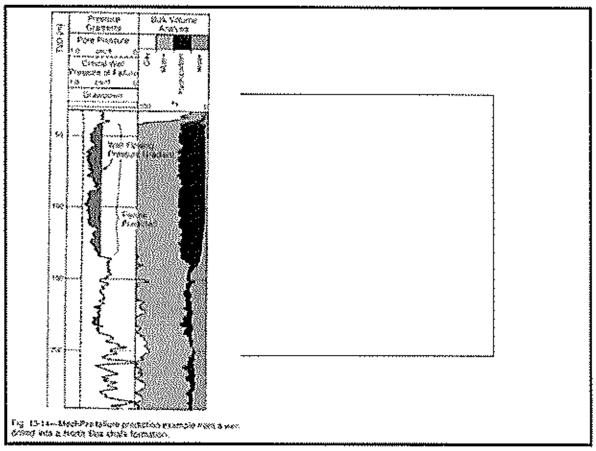

Four-Arm Caliper
Three-Arm Caliper

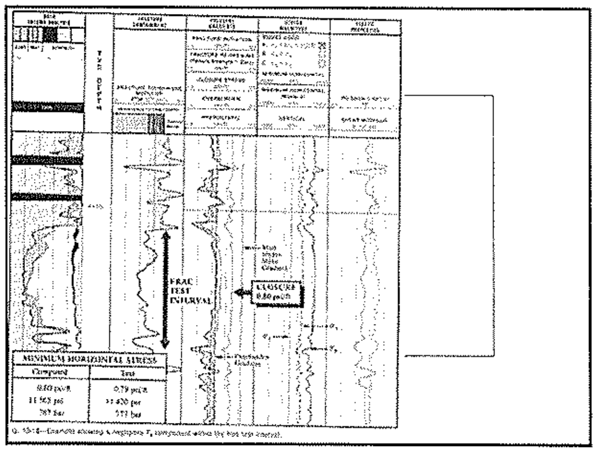

Fractures
Fig. 13-8—Fracture indications on FIL presentation of dipmeter data in Fig. 13-7.


Pad Azimuth
South
West
North
East
South
Fig. 13-9—FMS display showing open fractures









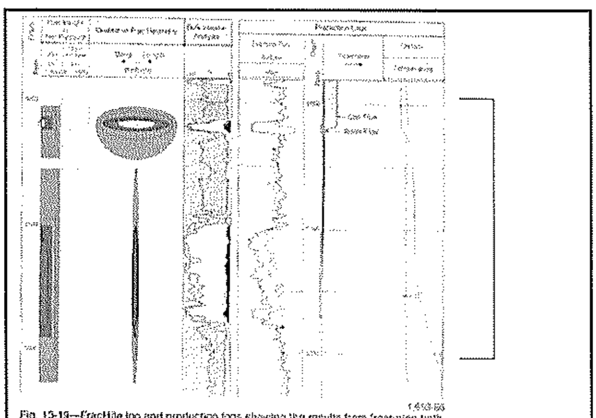


Fig. 13-19—FracHite log and production logs showing the results from fracturing both zones simultaneously.

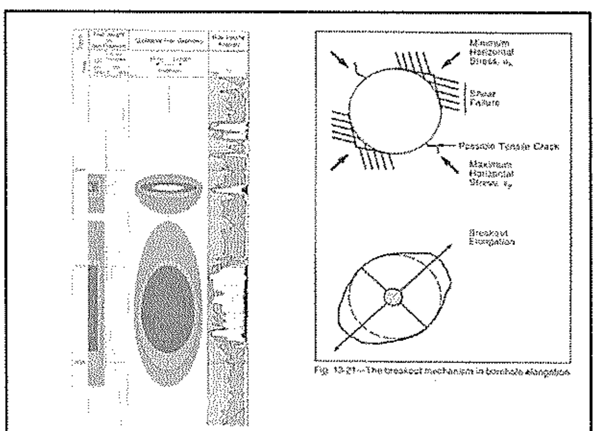
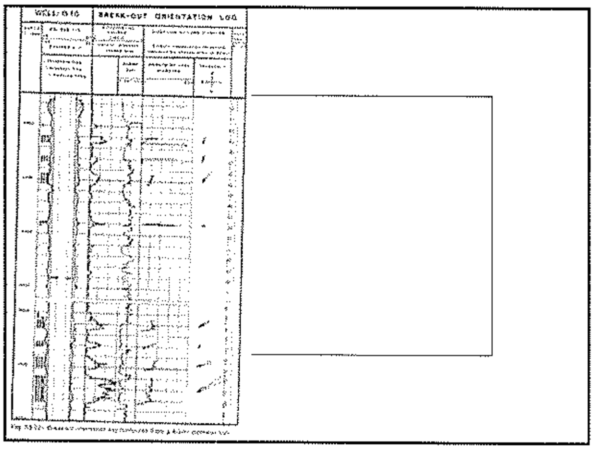
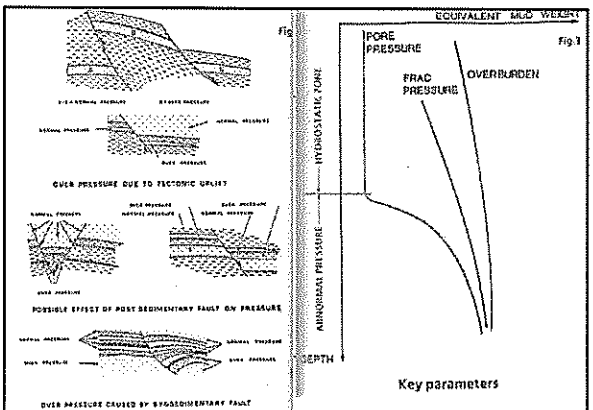


Fig. 13-20—FracHite log predicting results of fracturing each

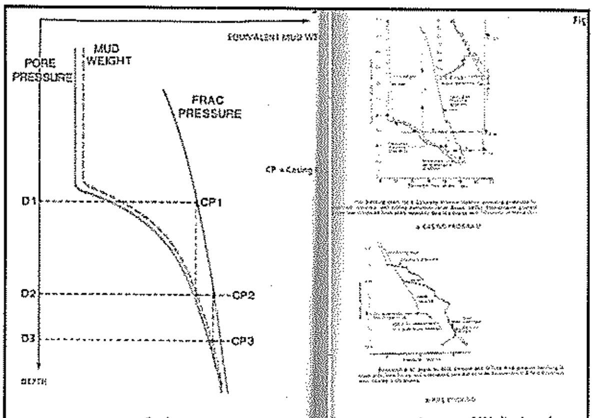
Fig. 13-21—The breakout mechanism in borehole elongation.





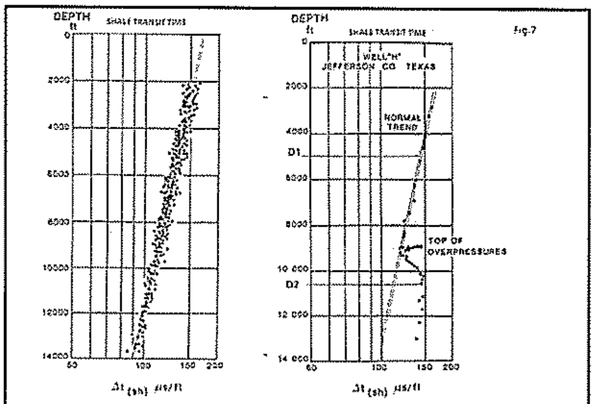
Some effects of tectonics on overpressure (after D.BILGERI et al,1982)

Key parameters



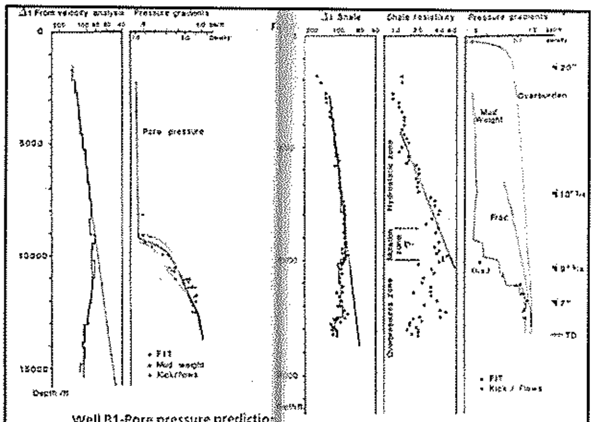
Casing program

Actual cases of Well-planning and pipe-sticking



Normal compaction trend

Shale compaction trend with evidence of overpressured zone



Well B1-Pore pressure prediction from seismic data

Well B1

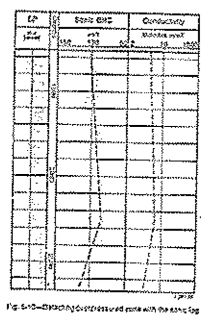


Fig. 5-10—Detecting overpressured zone with the sonic log

Sandstone, t_{ma} = 85 µs/ft

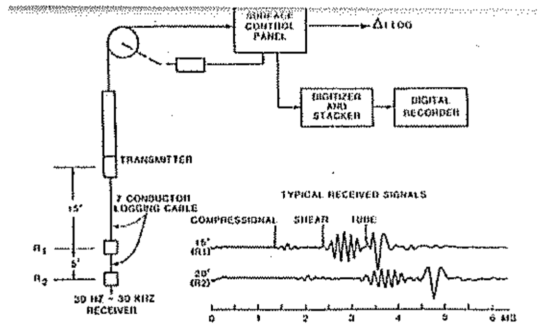
Limestone, t_{ma} = 90 µs/ft

Dolomite, t_{ma} = 75 µs/ft

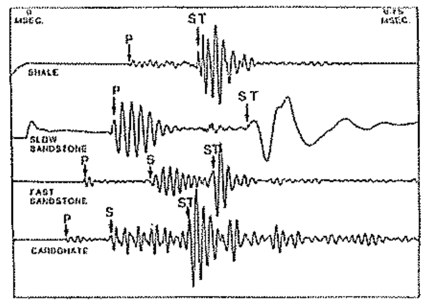
Anhydrite, t_{ma} = 100 µs/ft

Water, t_{ma} = 370 µs/ft

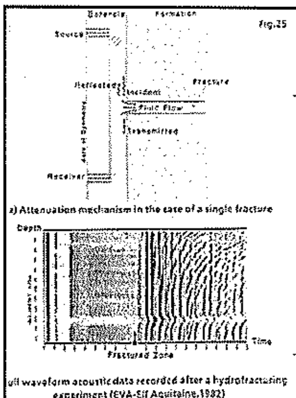
DENSITY LOGS



LSAL tool configuration and waveforms
(after D.M. WILLIAMS et al,1984)



LSAL waveforms in various lithologies T-R spacing 20 feet
(after D.M. WILLIAMS et al,1984)



Fracture identification on FWAL
(after F.MATHIEU and M.N.TOKSÖZ,1984)

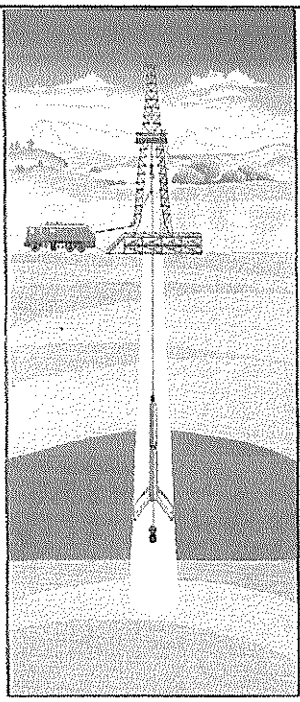


Fig. 1-2—Wireline logging operation.

WELLLOGGING

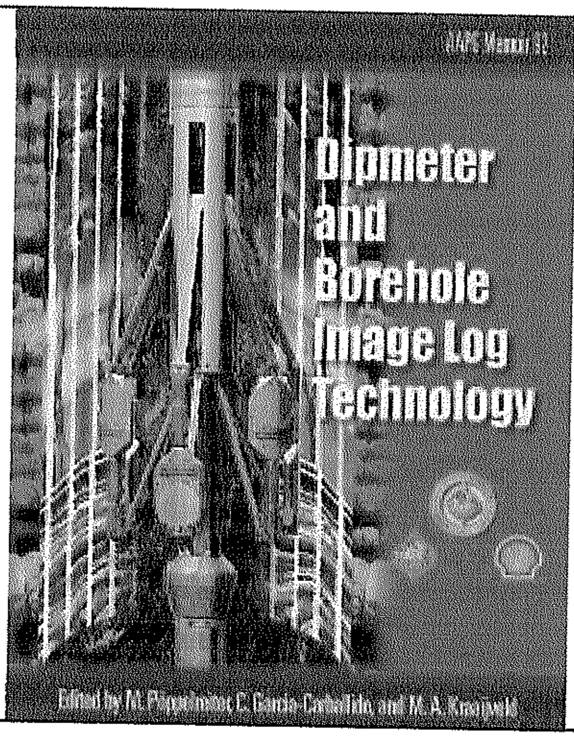
CHAPTER17

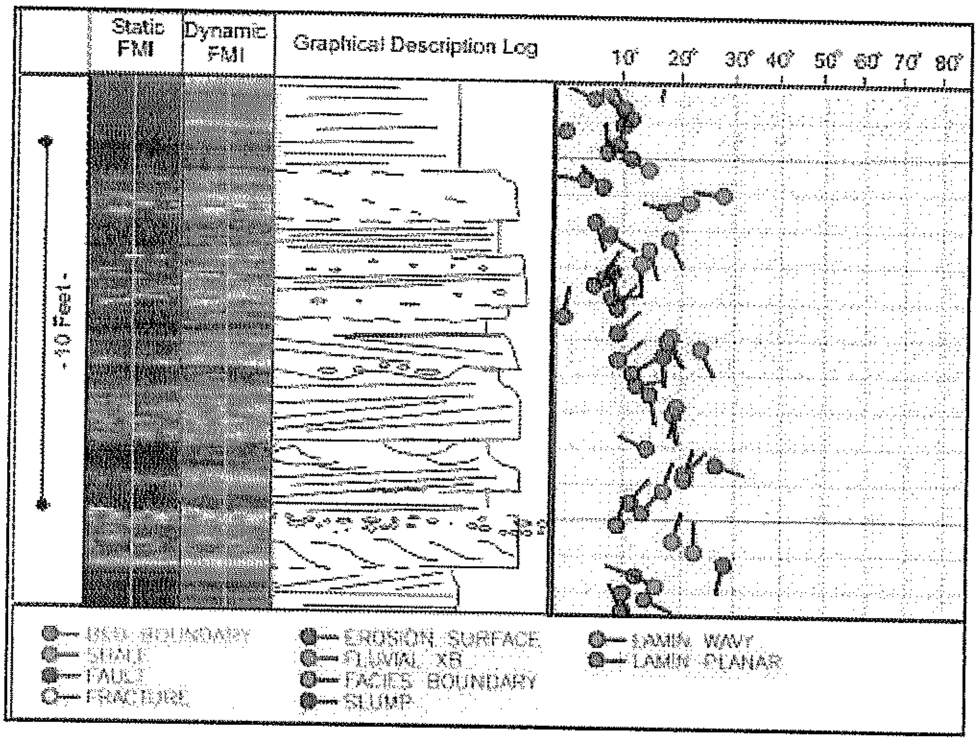
DIPMETER AND LOG CORRELATION

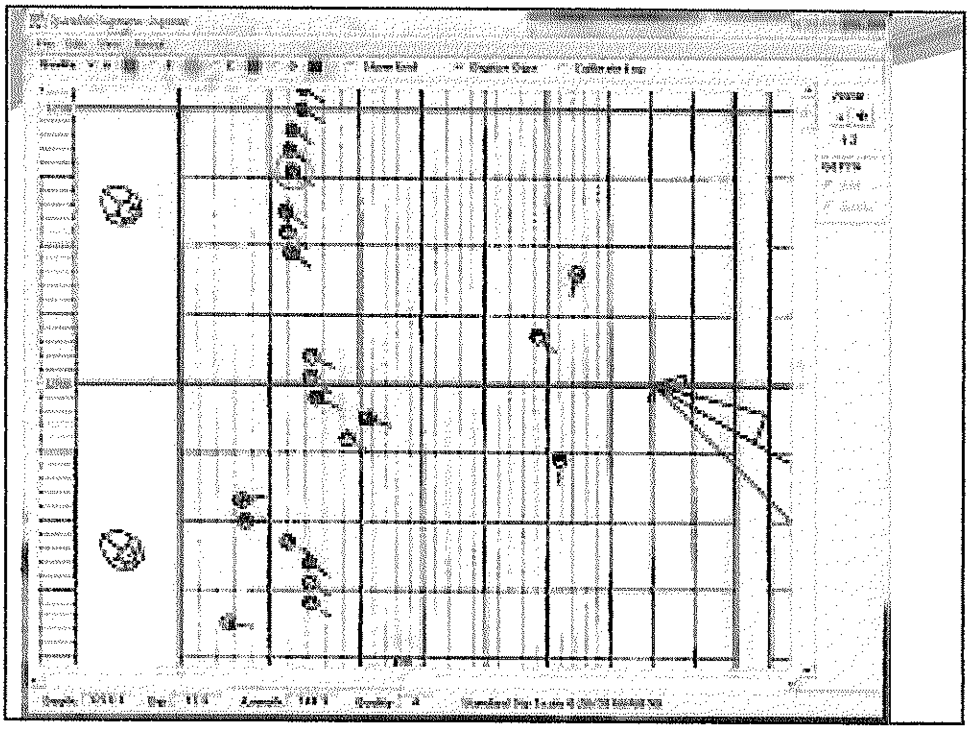
Spontaneous Potential (SP) Log(2 hrs.)
Induction Electric and Dual Induction Logs(2 hrs.)
Acoustic , Gamma Ray and Caliper Logs(2 hrs.)
Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Abnormal Pressure(1 hr.)
Fracture Detection with Well Logs(1 hr.)

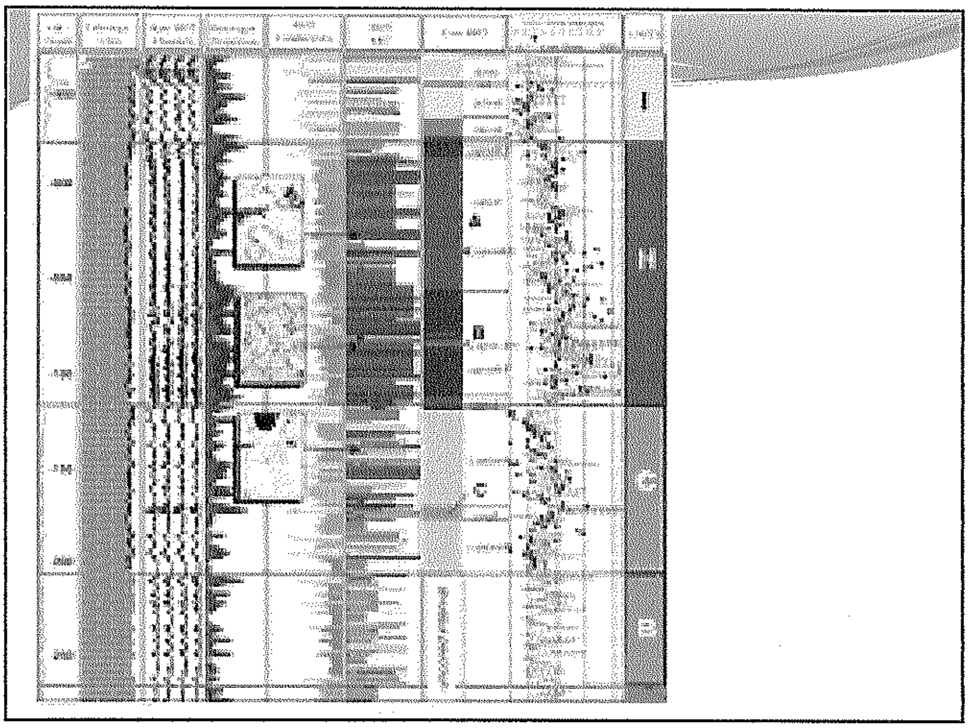
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)

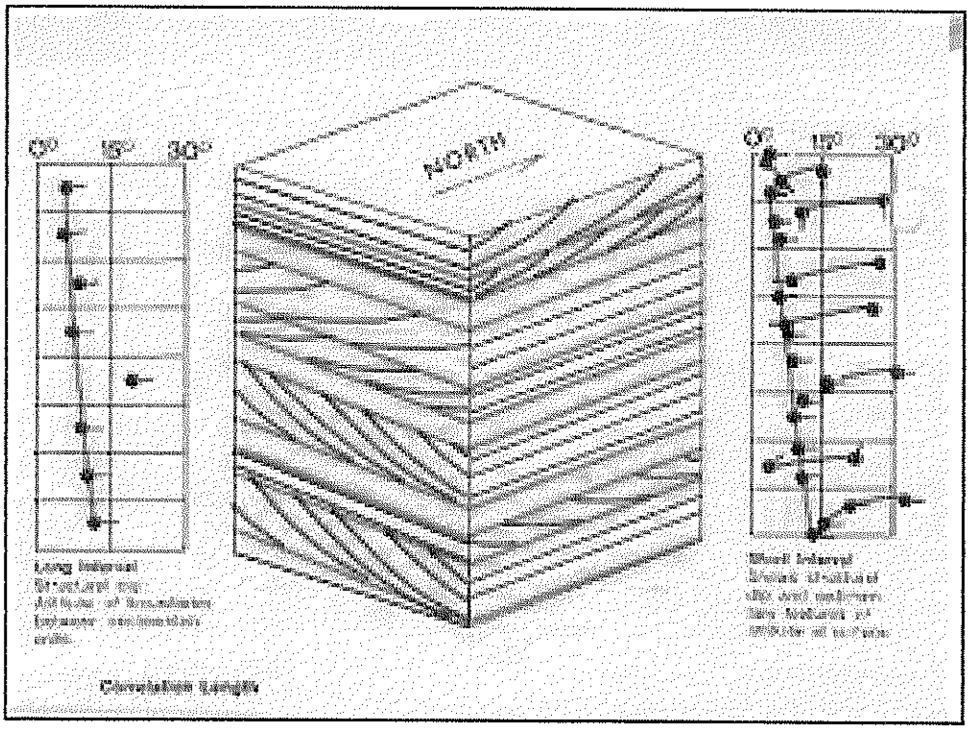
Special Logs(1 hrs.)

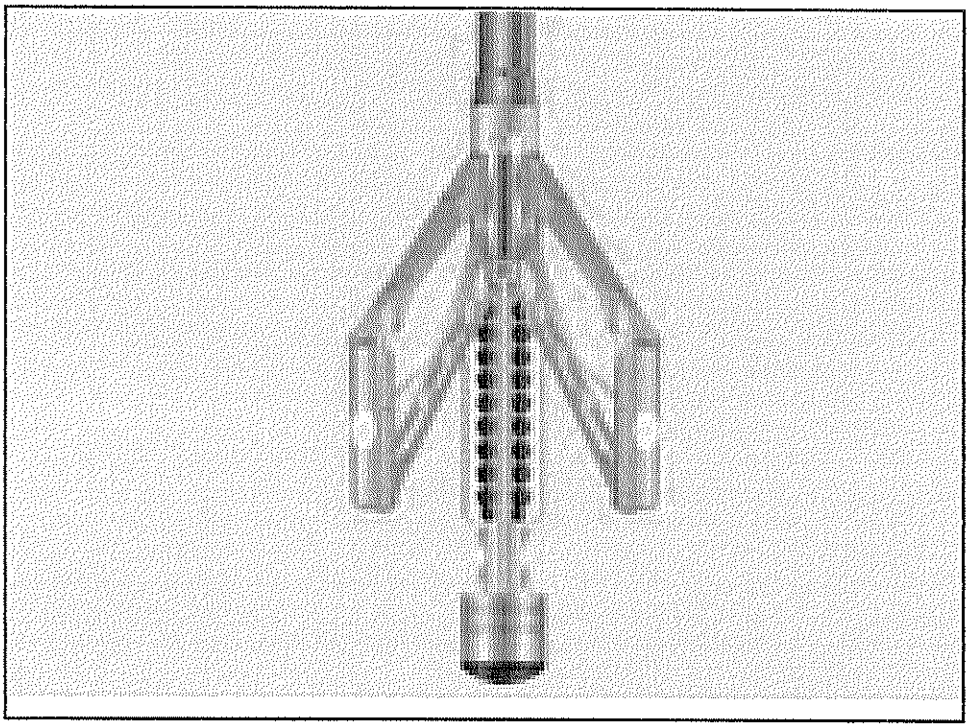

Dipmeter and Borehole Image Log Technology


Static FMI
Dynamic FMI
Graphical Description Log
10° 20° 30° 40° 50° 60° 70° 80°
- 10 Feet -
FRACTURE
EROSION SURFACE
FLUVIAL XB
FACIES BOUNDARY
SLUMP
LAMIN WAVY
LAMIN PLANAR






0°
15°
30°
NORTH



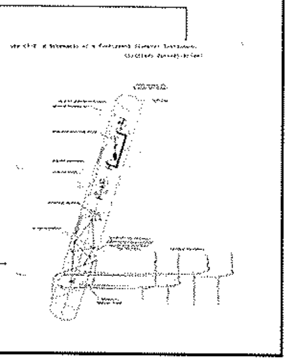
DIP METER

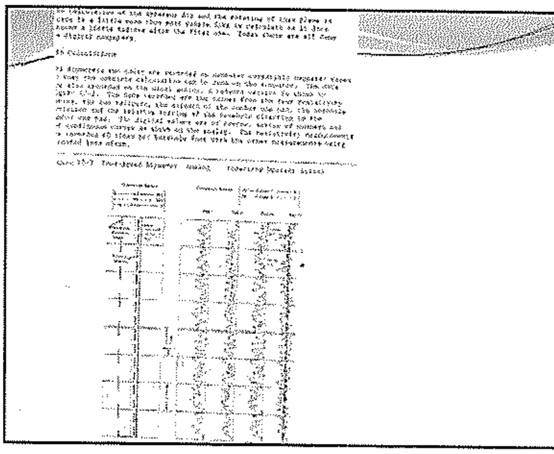
: IS A LOGGING DEVICE THAT MEASURE THE DIP AND DIP DIRECTION OF BEDS INTERSECTING THE BOREHOLE.
: USING THREE-POINTS METHOD GRAPHICALLY.

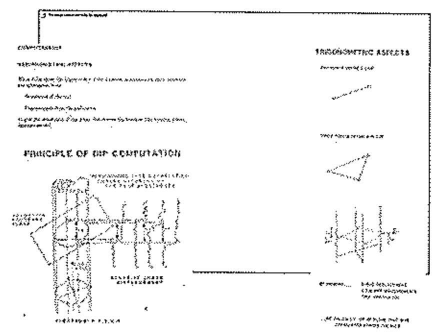
DIP IN FORMATION:
- WHERE TO DRILL THE NEXT BOREHOLE
- PROJECTING THE EDGE OF THE RESERVOIR
- STRATIGRAPHIC INFORMATION.
- LOCATING OF FAULTS /UNCONFORMITY / STRUCTURAL DIP etc.

DIPMETER INSTRUMENT: (FIG. 1)
- FOUR-ARMED RESISTIVITY METERS
- COMPASS (AZIMUTH/BEARING)
- TWO CALIPERS
- A PENDULUM
- COMPUTER

DIP CALCULATION: (FIG. 2)
- BY COMPUTER
- DATA RECORDED ARE FROM FOUR RESISTIVITY CURVES, TWO CALIPERS, AZIMUTH NUMBER OF ONE PAD, BOREHOLE DEVIATION, RELATIVE BEARING OF THE BOREHOLE DIRECTION TO ONE PAD.
- RESISTIVITY MEASUREMENT = 60 TIMES PER BOREHOLE FOOT.







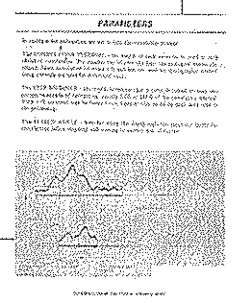
CORRELATION LENGTH. (FIG. 3)
: IS THE INTERVAL ON THE R. DATA THAT WILL BE CORRELATED TO DETERMINE THE APPARENT DIP (ONE APP. DIP FOR ONE INTERVAL).
1. LONG CORRELATION LENGTH (ex. 8-15 FT)
- STRUCTURAL DIPS IN SILTY, SHALE ZONE.
2. SHORT CORRELATION LENGTH
- BEDDING PLANES, GRAIN SIZE VARIATION AND SHALINESS CHANGES. 4 ft

TAD POLES (VECTOR) (FIG. 4)
: REPRESENT A SINGLE DIP CALCULATION (DIP ANGLE DIRECTION PRESENT BY THE ARROW DIRECTION).

SEARCH INTERVAL (ANGLE)
- THE HIGHEST ANGLE THAT APP. DIP WILL BE SEARCHED FOR BY THE PROGRAM.
: ANY BEDS WITH APP. DIPS GREATER THAN THE SEARCH ANGLE ARE IGNORED.

STEPS.
: THE DISTANCE BETWEEN DIPS CALCULATION.
: ¼ OF THE CALCULATION LENGTH (FOR OVERLAPPING). (FIG. 5)

NOTE : SELECTION OF SEARCH ANGLE, CORRELATION LENGTH AND STEP SIGNIFICANTLY INFLUENCE TIME AND COST OF COMPUTING.



he calculation of the apparent dip and the rotating of this plane in pace is a little more than most people like to calculate as it does ecome a little tedious after the first one. Today these are all done n digital computers.

ip Calculations

ll dipmeters run today are recorded on computer compatible magnetic tapes o that the complete calculation can be done on the computer. The data re also recorded on the usual analog. A reduced version is shown in igure 17-2. The data recorded are the values from the four resistivity urves, the two calipers, the azimuth of the number one pad, the borehole eviation and the relative bearing of the borehole direction to the umber one pad. The digital values are of course, series of numbers and ot continuous curves as shown on the analog. The resistivity measurements re recorded 60 times per borehole foot with the other measurements being epeated less often.

igure 17-2 Four-Armed Dipmeter Analog (courtesy Dresser Atlas)

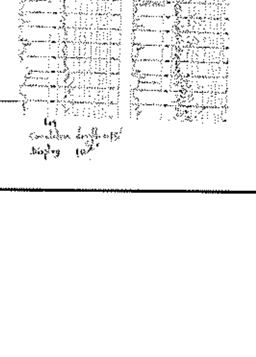
CORRELATION LENGTH. (FIG. 3)
: IS THE INTERVAL ON THE R. DATA THAT WILL BE CORRELATED TO DETERMINE THE APPARENT DIP (ONE APP. DIP FOR ONE INTERVAL).
1. LONG CORRELATION LENGTH (ex. 8-15 FT)
- STRUCTURAL DIPS IN SILTY, SHALE ZONE.
2. SHORT CORRELATION LENGTH
- BEDDING PLANES, GRAIN SIZE VARIATION AND SHALINESS CHANGES.

TAD POLES (VECTOR) (FIG. 4)
: REPRESENT A SINGLE DIP CALCULATION (DIP ANGLE DIRECTION PRESENT BY THE ARROW DIRECTION).

SEARCH INTERVAL (ANGLE)
: THE HIGHEST ANGLE THAT APP. DIP WILL BE SEARCHED FOR BY THE PROGRAM.
: ANY BEDS WITH APP. DIPS GREATER THAN THE SEARCH ANGLE ARE IGNORED.

STEPS.
: THE DISTANCE BETWEEN DIPS CALCULATION.
: ¼ OF THE CALCULATION LENGTH (FOR OVERLAPPING). (FIG. 5)

NOTE : SELECTION OF SEARCH ANGLE, CORRELATION LENGTH AND STEP SIGNIFICANTLY INFLUENCE TIME AND COST OF COMPUTING.



CORRELATION LENGTH (FIG. 3)
: IS THE INTERVAL ON THE R. DATA THAT WILL BE CORRELATED TO DETERMINE THE APPARENT DIP (ONE APP. DIP FOR ONE INTERVAL).

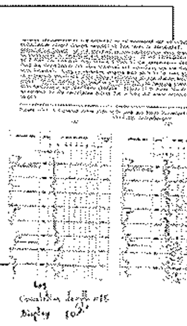
1. LONG CORRELATION LENGTH (ex. 8-15 FT)
   - STRUCTURAL DIPS IN SILTY, SHALE ZONE.
2. SHORT CORRELATION LENGTH
   - BEDDING PLANES, GRAIN SIZE VARIATION AND SHALINESS CHANGES

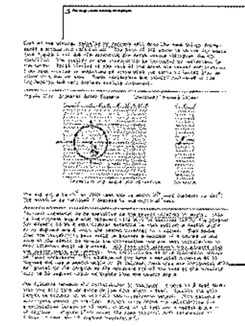
TAD POLES (VECTOR) (FIG. 4)
: REPRESENT A SINGLE DIP CALCULATION (DIP ANGLE DIRECTION PRESENT BY THE ARROW DIRECTION).

SEARCH INTERVAL (ANGLE)
: THE HIGHEST ANGLE THAT APP. DIP WILL BE SEARCHED FOR BY THE PROGRAM.
: ANY BEDS WITH APP. DIPS GREATER THAN THE SEARCH ANGLE ARE IGNORED.

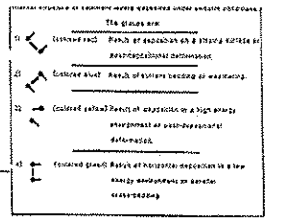
STEPS.
: THE DISTANCE BETWEEN DIPS CALCULATION.
: ½ OF THE CALCULATION LENGTH (FOR OVERLAPPING). (FIG. 3)

NOTE : SELECTION OF SEARCH ANGLE, CORRELATION LENGTH AND STEP SIGNIFICANTLY INFLUENCE TIME AND COST OF COMPUTING.





TAD POLES (VECTOR) (FIG. 4)
: REPRESENT A SINGLE DIP CALCULATION (DIP ANGLE DIRECTION PRESENT BY THE ARROW DIRECTION).



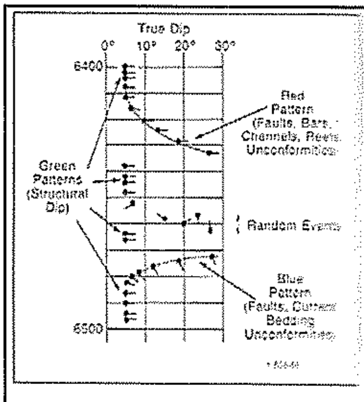
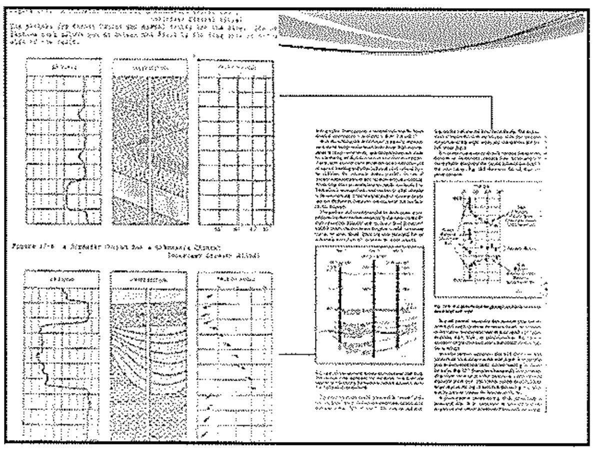
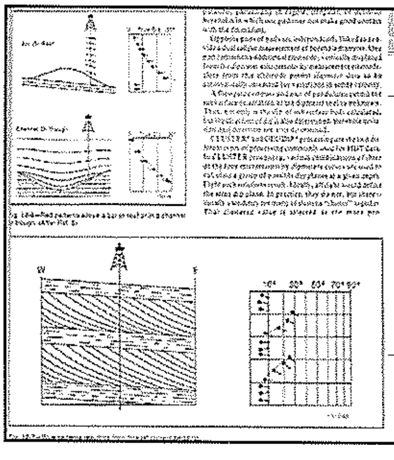
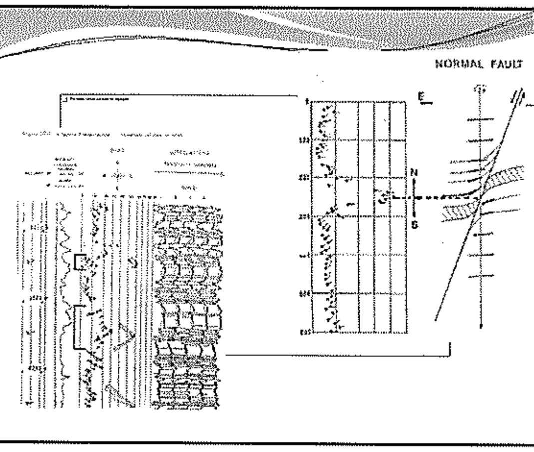


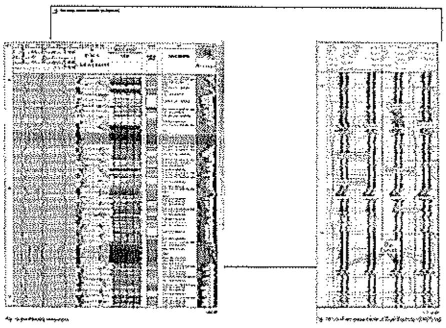
Fig. 12-5—Dip patterns and the geologic anomalies commonly associated with them.

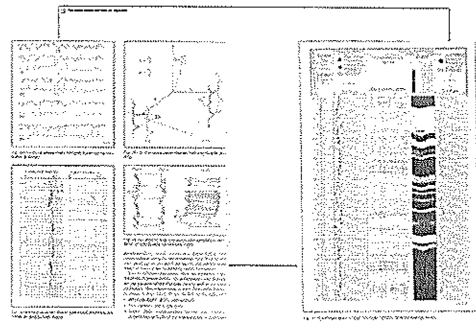


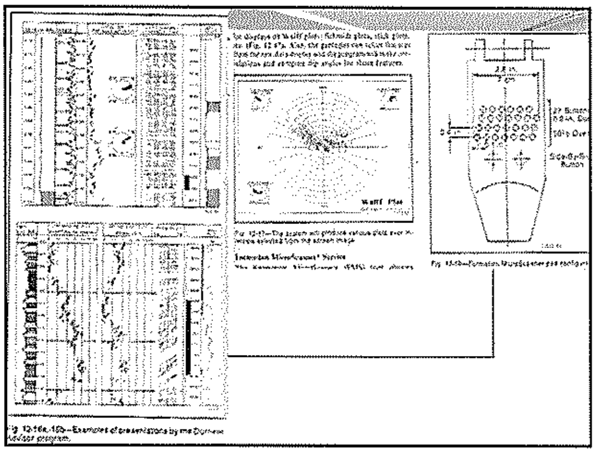


NORMAL FAULT









for displays of Wulff plots, Schmidt plots, stick plots, etc. (Fig. 12-17). Also, the geologist can select features from the raw data display and the program will make correlations and compute dip angles for those features.

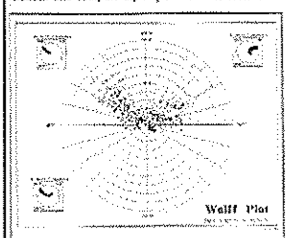


Fig. 12-17—The system will produce various plots over intervals selected from the screen image.

Formation MicroScanner' Service

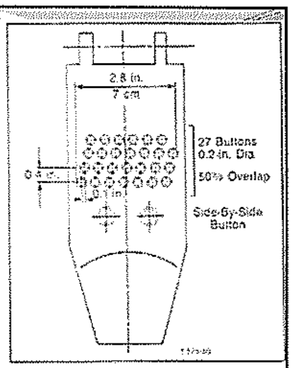
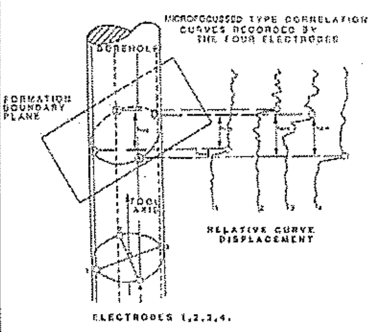


Fig. 12-13—Formation MicroScanner pad configuration.

PRINCIPLE OF DIP COMPUTATION



USES FOR THE DIPMETER

GROSS STRUCTURAL FEATURES:

- STRUCTURAL DIP
- DIP PATTERNS
- FAULTS
- FOLDING
- UNCONFORMITIES
- CONTOUR MAPS

SMALL-SCALE FEATURES:

- FINE STRATIGRAPHIC DETAIL
- FACIES CHARACTERISATION IN CARBONATE SECTIONS
- PALAEOCURRENT DIRECTION
- THIN BED RECOGNITION
- BED BOUNDARY TYPE
- IDENTIFYING POSSIBLE PERMEABILITY BARRIERS
- IDENTIFYING INHOMOGENETIES
- FRACTURE DETECTION
- CORE DEPTH CORRELATION

The uses of the dipmeter are many varying from gross structural dip to fine sedimentory features and reservoir characteristics.

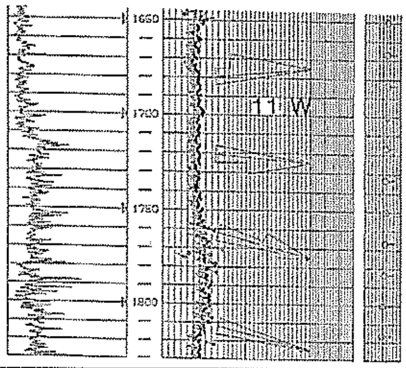
Some of the possible uses are listed.

Structural features (generally resulting from laterally directed forces acting on the structures as a whole) :

- structural dip - the main dip of the beds
- faults - natural fracture marking a displacement
- fold - synclines/anticlines
- unconformities - gaps in the regular stratigraphic sequence
- contour maps - knowing depths and dip directions the field contours can be mapped

Stratigraphic features, (generally sedimentary characteristics such as bedding, paleocurrents, thin beds etc.

STRUCTURAL DIP



Adjacent tadpoles form dip groups which are the building blocks of mega-patterns. The dips forming such groups are derived from the internal structure of sediment layers deposited under uniform conditions.

The groups are;

1) (colored red) Result of deposition on a sloping surface or post-depositional deformation.

2) (colored blue) Result of current bedding or weathering.

3) (colored yellow) Result of deposition in a high energy environment or post-depositional deformation.

4) (colored green) Result of horizontal deposition in a low energy environment or parallel cross-bedding.

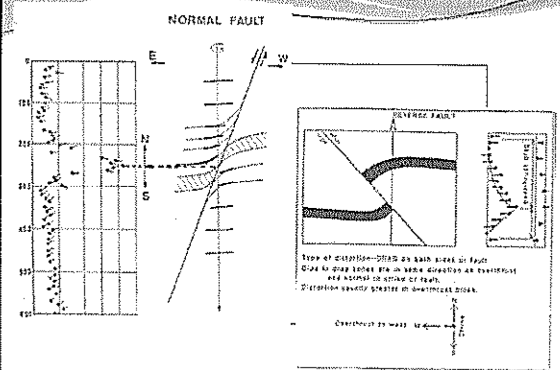
To facilitate the recognition of features, both structural and stratigraphic a colouring nomenclature is used.

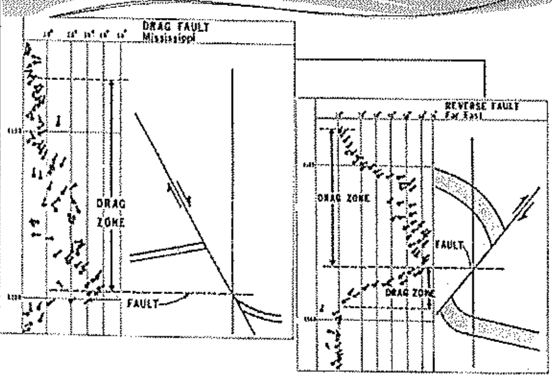
Adjacent dips which increase in magnitude towards the bottom of the hole are joined by a red line.

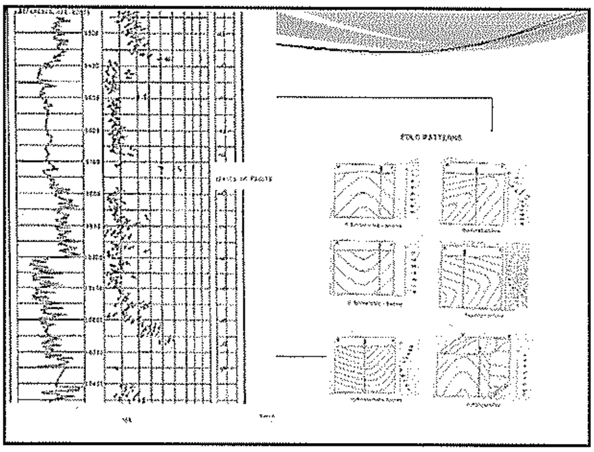
Dips decreasing in magnitude towards the bottom are joined by a blue line. The azimuth in red and blue patterns must stay reasonably constant.

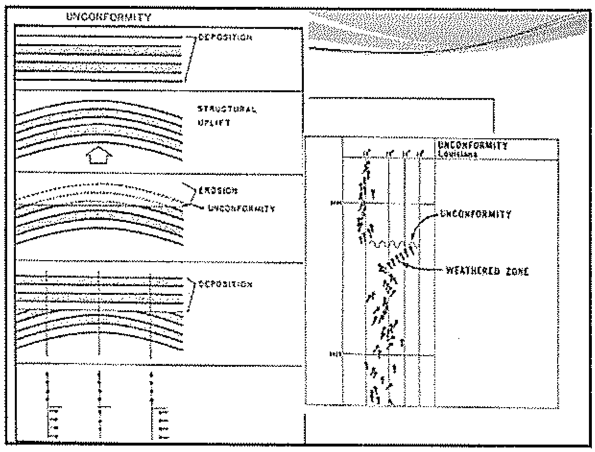
Dips not changing with depth are coloured green, structural dip.

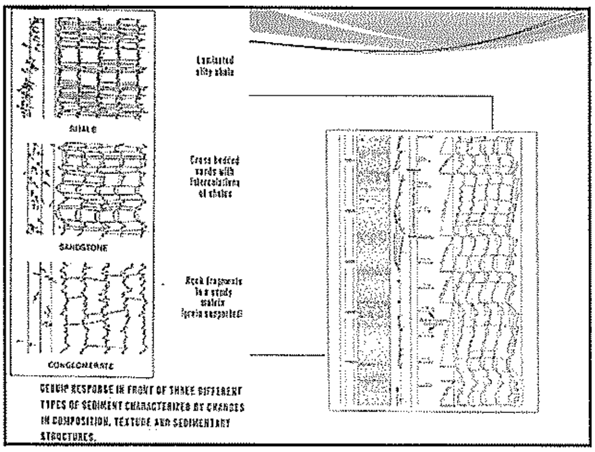
By putting these colours on a section of log it becomes easier to interpret since various combinations of patterns have differing meanings.

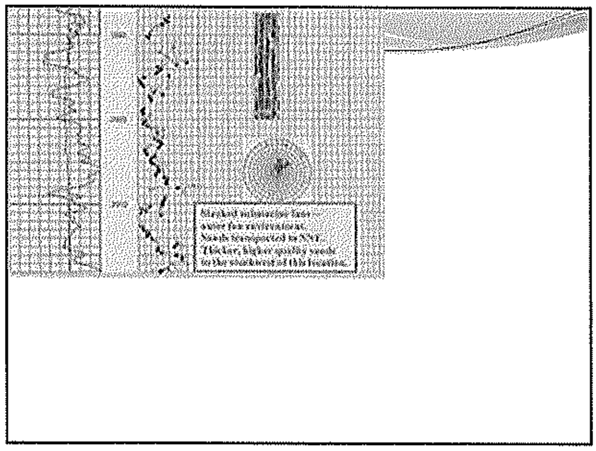


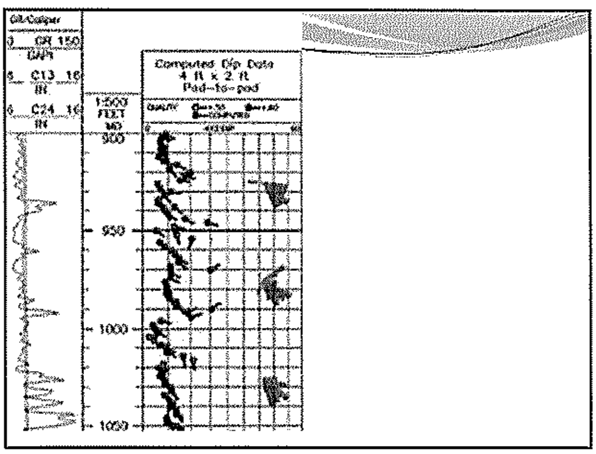


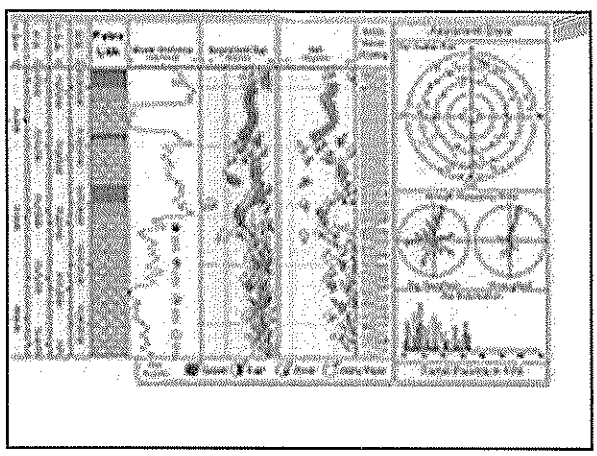

FOLD PATTERNS

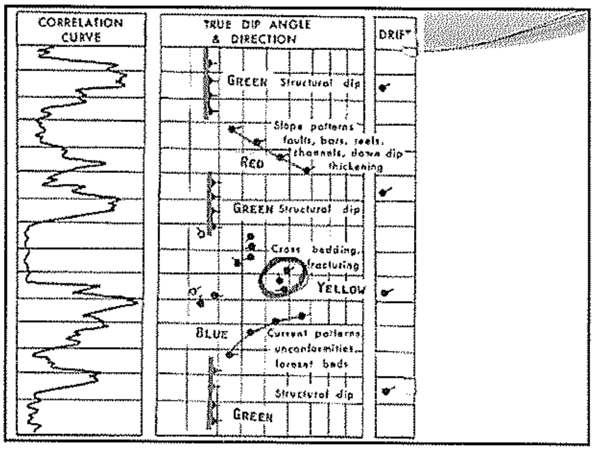

UNCONFORMITY
DEPOSITION
STRUCTURAL UPLIFT
EROSION
UNCONFORMITY
DEPOSITION
UNCONFORMITY
Louisiana
UNCONFORMITY
WEATHERED ZONE

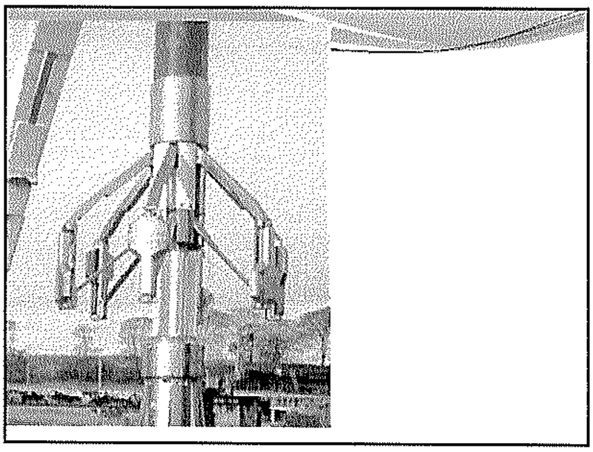

Laminated silty shale
SHALE
Cross bedded sands with intercalations of shales
SANDSTONE
Rock fragments in a sandy matrix (grain supported)
CONGLOMERATE
GEODIP RESPONSE IN FRONT OF THREE DIFFERENT TYPES OF SEDIMENT CHARACTERIZED BY CHANGES IN COMPOSITION, TEXTURE AND SEDIMENTARY STRUCTURES.

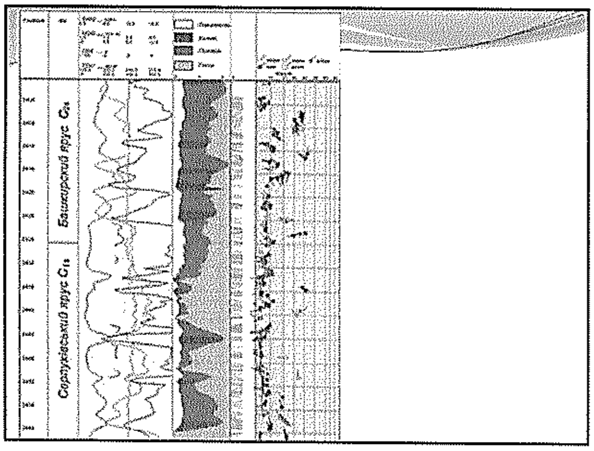


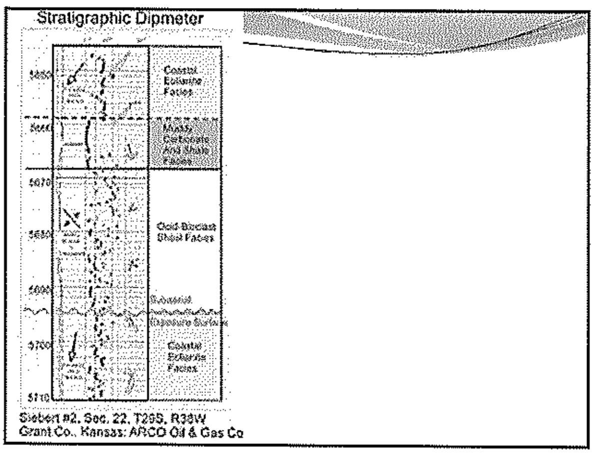

GR/Caliper
0 GR 150
GAPI
6 C13 16
IN
6 C24 16
IN
1:500
FEET
MD
Computed Dip Data
4 ft x 2 ft
Pad-to-pad
900
950
1000
1050

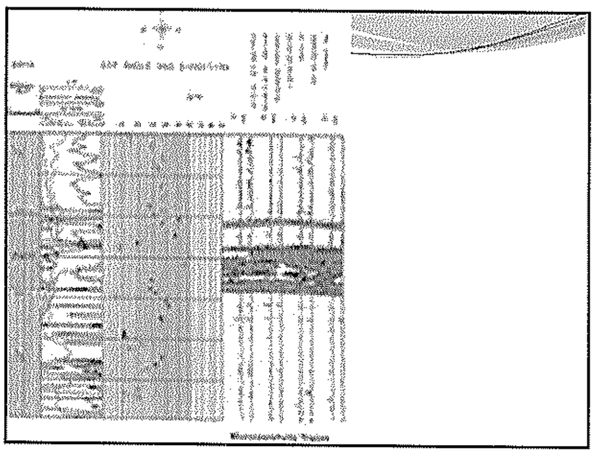


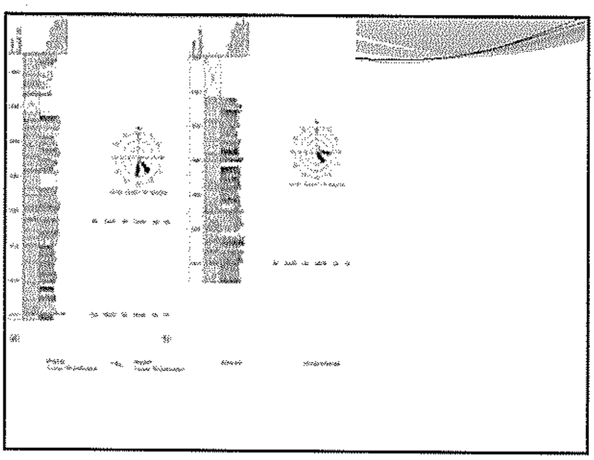

CORRELATION CURVE
TRUE DIP ANGLE & DIRECTION
DRIFT
GREEN Structural dip
Slope patterns faults, bars, reefs, channels, down dip thickening
RED
GREEN Structural dip
Cross bedding, fracturing
YELLOW
BLUE
Current patterns unconformities, foreset beds
Structural dip
GREEN

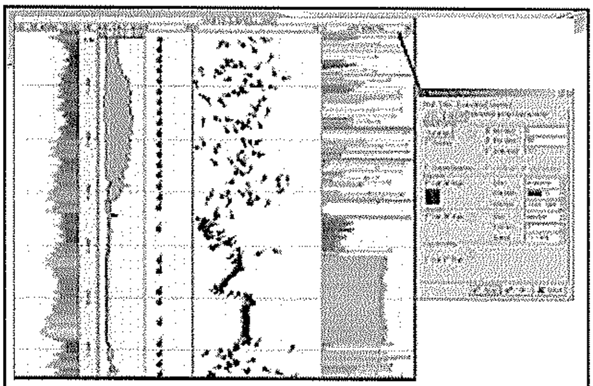


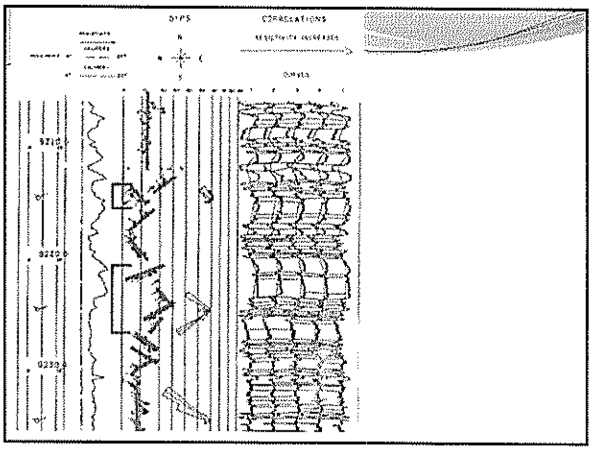

Башкирский ярус

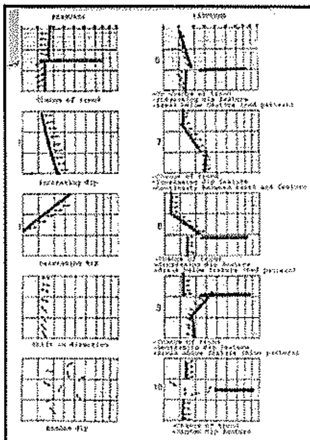

Stratigraphic Dipmeter
Coastal Eolianite Facies
Ooid-Bioclast Shoal Facies
Siebert #2, Sec. 22, T29S, R38W
Grant Co., Kansas: ARCO Oil & Gas Co



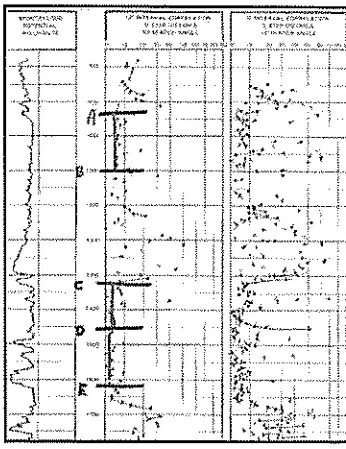




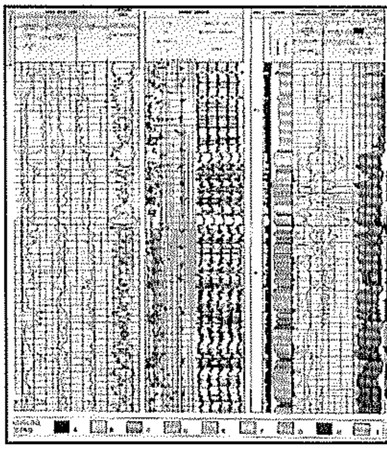




- Dipmeter patterns and features



Colouring and analyzing dipmeter patterns

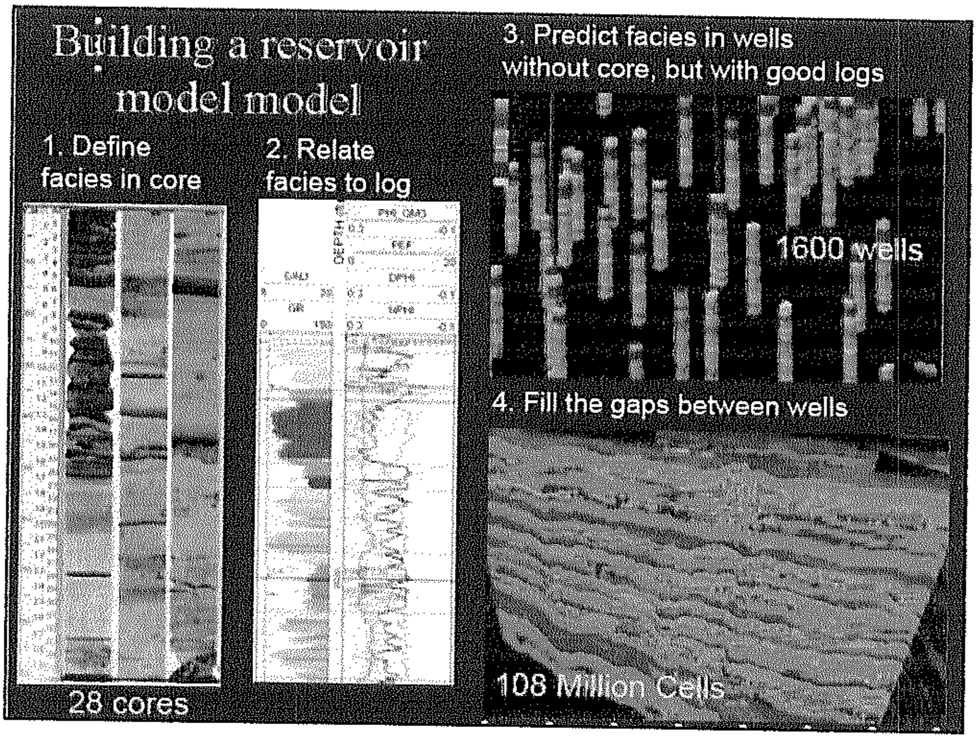


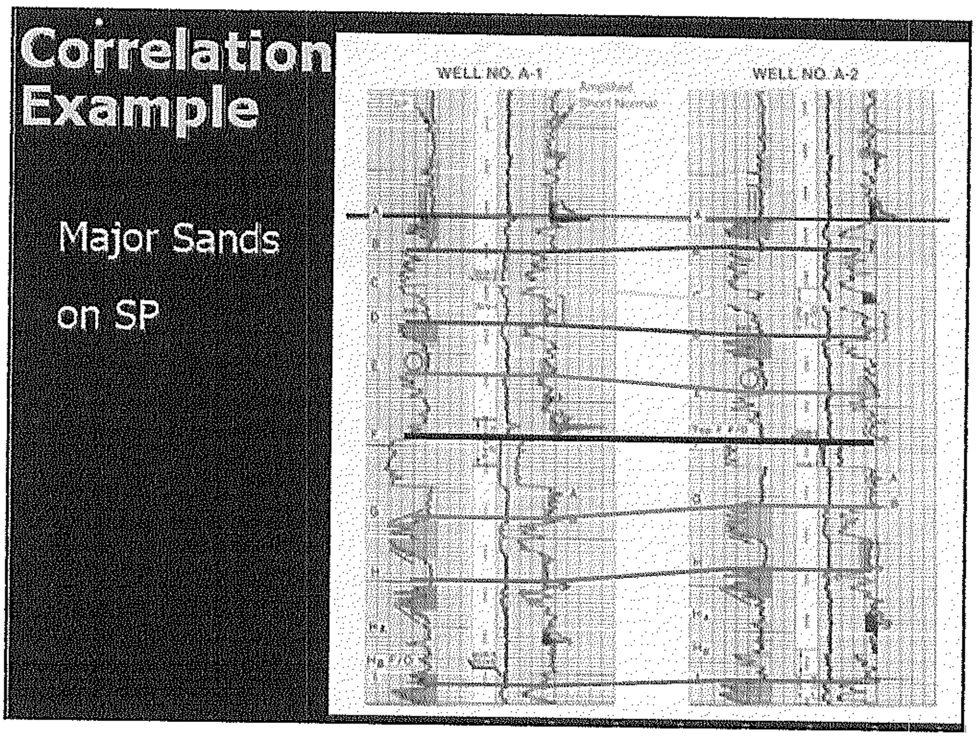
Analyze dipmeters along with all available data - not in isolation

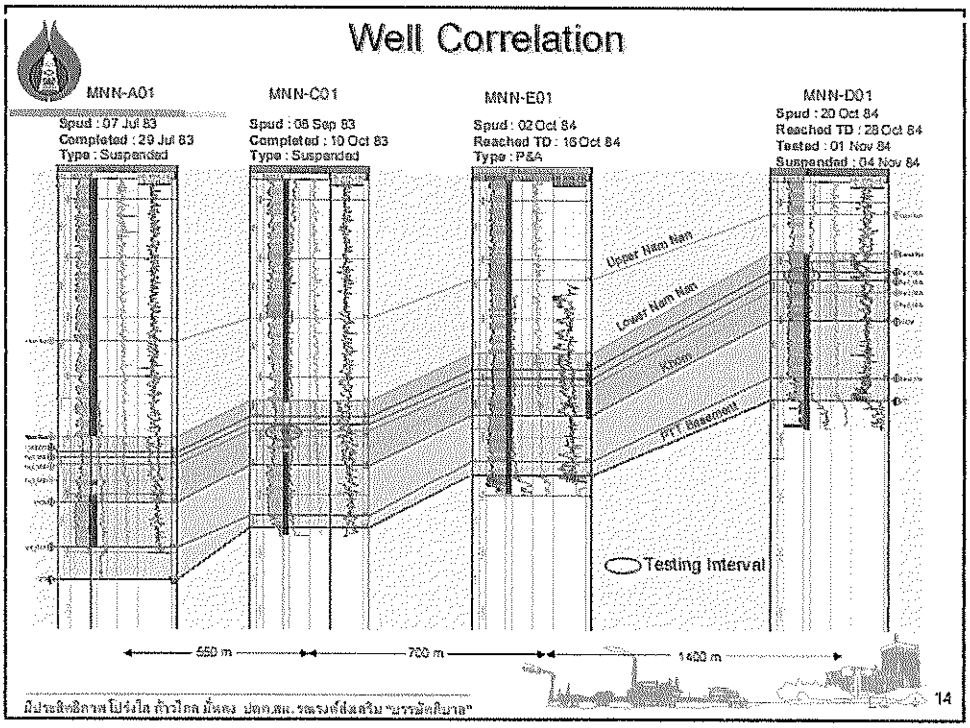
LOG CORRELATION

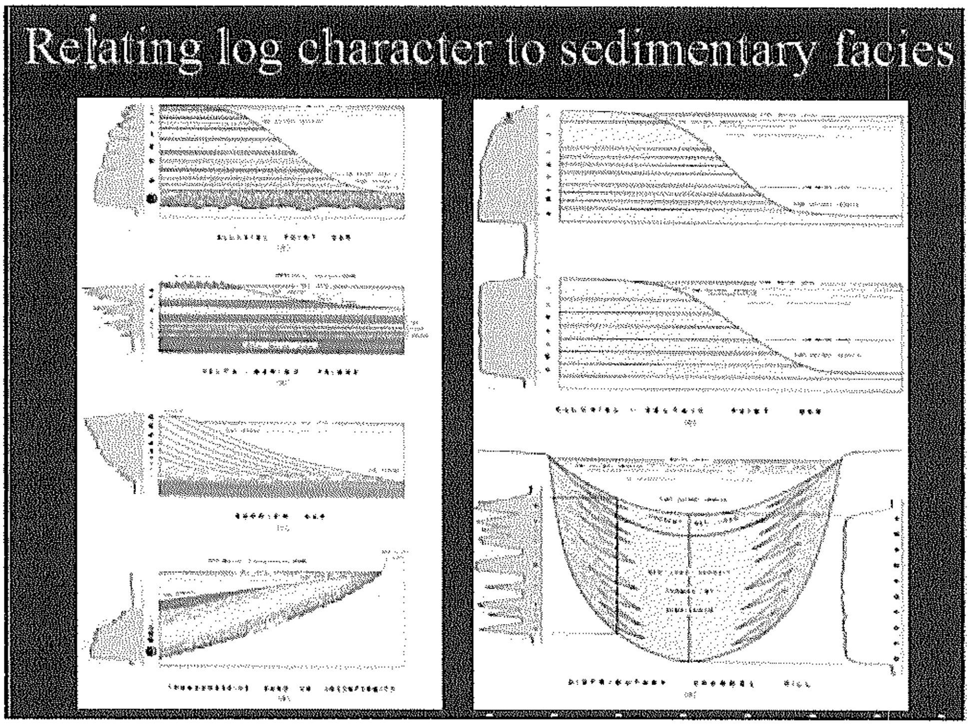
Applications of logs

- Stratigraphic studies
  - Sedimentary facies
- Well correlation
- Reservoir models
- Structural interpretation
  - Fault recognition

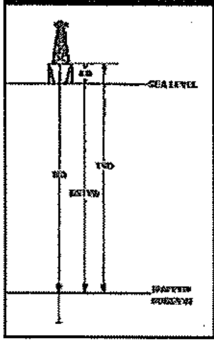

Building a reservoir model model
1. Define facies in core
2. Relate facies to log
3. Predict facies in wells without core, but with good logs
1600 wells
4. Fill the gaps between wells
108 Million Cells
28 cores


Correlation Example
Major Sands
on SP
WELL NO. A-1
WELL NO. A-2


Well Correlation
MNN-A01
Spud : 07 Jul 83
Completed : 29 Jul 83
Type : Suspended
MNN-C01
Spud : 08 Sep 83
Completed : 10 Oct 83
Type : Suspended
MNN-E01
Spud : 02 Oct 84
Reached TD : 16 Oct 84
Type : P&A
MNN-D01
Spud : 20 Oct 84
Reached TD : 28 Oct 84
Tested : 01 Nov 84
Suspended : 04 Nov 84
Upper Nam Nan
Lower Nam Nan
Khom
PTT Basement
Testing Interval
550 m
700 m
1400 m
14

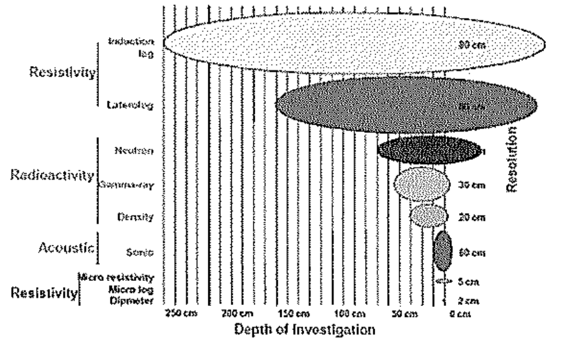

Relating log character to sedimentary facies

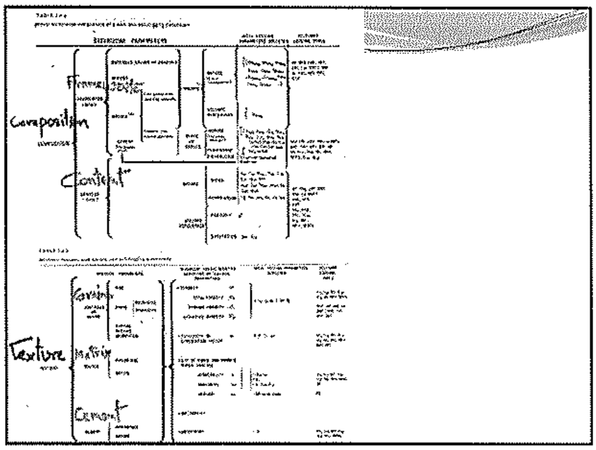
Log Datum Terminology

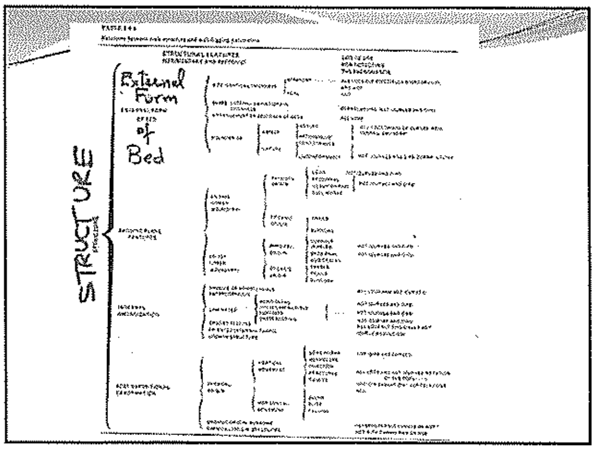


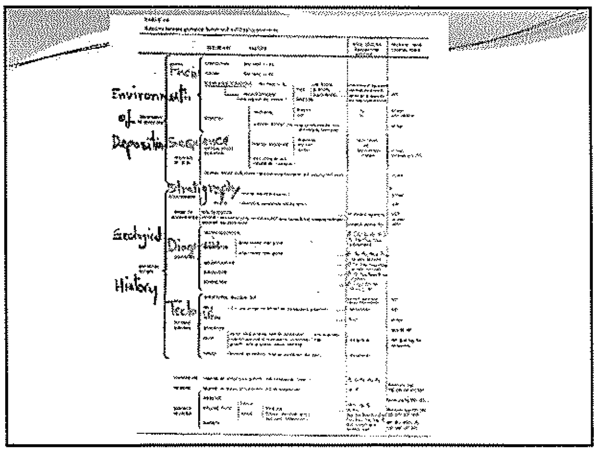
- KB - Kelly Bushing elevation.
- MD - Measured Depth along the wellbore from the Kelly bushing (usually)
- SS - Depth Relative to Sealevel
- TVD – True Vertical Depth, (important for non-vertical wells)
- SSTVD - Sub-Sea True Vertical Depth

Depth of Investigation and Resolution of Logging Tools









LOG CORRELATION TECHNIQUES

Correlation : the determination of structural or stratigraphic units that are equivalent in time, age, or stratigraphic position.

Objectives : 1) Subsurface map
2) Geologic cross section

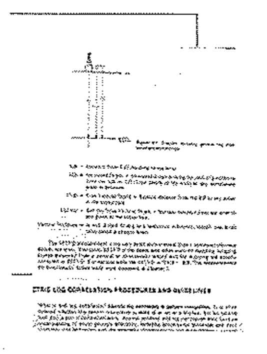
Tools : 1) Electric wire line logs
2) Seismic sections.
for a detailed geologic/ geophysics study.

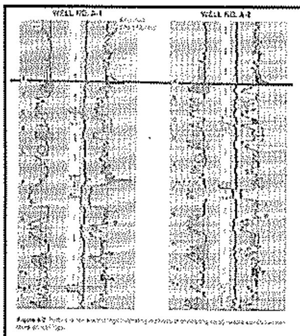
Note : 1. Accurate correlations are paramount for reliable geological interpretations.
2. No geologic interpretation can be prepared without detailed electric log correlation.

GENERAL LOG MEASUREMENT TERMINOLOGY

DEPTH (ft / m / km)

: An understanding of several log depth measurements is important for converting log depths used for mapping. (FIG. 1)





DATA PRESENTED ON WELL LOG:

1) Subsurface formations (tops / bases)
2) Depth and size of faults
3) Lithology
4) Depth to, and thickness of hydrocarbon bearing zones
5) Porosity, permeability, etc. of productive zones
6) Raw data used to prepare subsurface maps, such as faults, structures, salts, unconformities, etc

Note : Incorrect correlation = dry hole

PROCEDURES AND GUIDELINES.

- LOGGING ARRANGEMENT (FIG. 3)
- PROCEDURES
  1) Align the depth scale of the logs, look for correlation
  2) If no correlation is evident, begin to slide one of the logs until a good correlation point is found, mark it.
  3) Continue this process over the entire length of each log until all recognized correlations have been identified.

Problems : Stratigraphic thinning, bed dipping, faulting, unconformities, lateral facies changes, poor log quality, directionally drilled wells.

PROCEDURES AND GUIDELINES.

- LOGGING ARRANGEMENT (FIG. 3)
- PROCEDURES
  1) Align the depth scale of the logs, look for correlation
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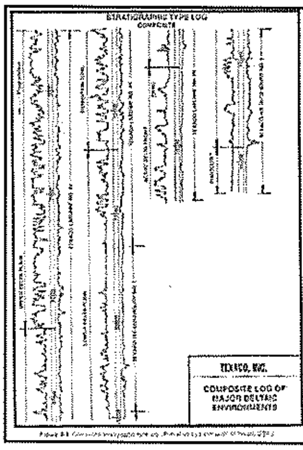
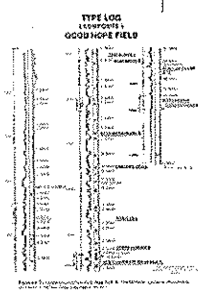
Problems : Stratigraphic thinning, bed dipping, faulting, unconformities, lateral facies changes, poor log quality, directionally drilled wells.





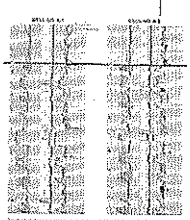
Note : 1) SSTVD is the depth ... used for mapping
2) Logging depths measured from a vertically drilled well for mapping ... corrected to SSTVD.

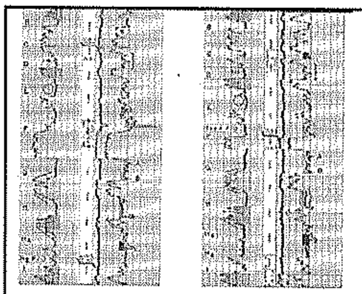
ELECTRIC LOG CORRELATION PROCEDURES AND GUIDELINES

INTERPRETER :

Geologic concepts
- Deposition processes
- Environments
- ...
- ...
- ...

Note : compare one log to another and match the pattern of curves ... to the pattern of curves found on the second log. (FIG. 2)





1. For initial quick look correlations, review major sand or carbonate bodies using the SP curve or gamma ray curve.
2. For detailed correlation work, first correlate shale sections.
3. Initially, use the amplified shallow resistivity curve (lateral or short normal), which usually provides the most reliable shale correlations.
4. Use colored pencils to identify specific correlation points.
5. Always begin correlation at the top of the log, not the middle.
6. Overview the entire log.
7. Do not force a correlation.
8. In highly faulted areas, first correlate down the log and then correlate up the log.

• GUIDELINES FOR QUICK-LOOK LOG CORRELATION (FIG. 2)

1. For initial Quick-look, Pursue Major Sandstones Using SP or Gamma Ray

Note:

1.1) Concentrate correlation work on shale section.

1st: clay, mud particles are deposited in low-energy region which responsible for shale deposition commonly cover large geographic areas.

: log curves (log signatures) in shale are often highly correlatable from well to well, and can be recognized over long distance

2nd: prominent sand beds are often not good correlation markers because they frequently exhibit significant variation in thickness and character from well to well, and are often laterally discontinuous

3rd: resistivity curves for the same sand on 2 well logs being correlated may be different, causing from variations in fluid content in a sand bed pronounced resistivity differences (i.e. water, gas)

2) Individual shale bed exhibit distinctive resistivity characteristics over large areas. Therefore, the amplified short normal resistivity curve provides the most reliable shale correlation. Because the amplified short normal is 5 times more sensitivity than others, and exhibits pattern that are easier to recognize and correlate from well to well (FIG. 2)

3) Use colored pencil to identify and mark correlation pattern on well logs (peak, valley, etc.)

4) Do not mark on original logs.

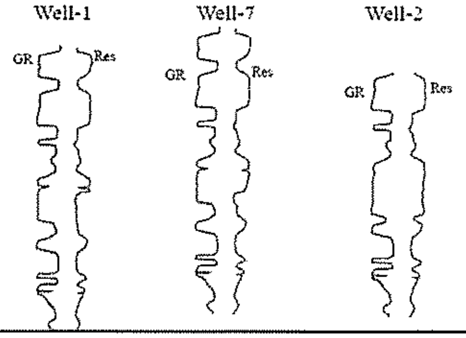
5) Structures become less complicate toward the surface.

6) Correlation work on the simple area first. Then, when the remainder of problem log and other logs have been correlates, the questionable correlation, such as faults, high bed dips, unconformity, facies changes, would be review again. Always begin correlation at the top of the log, not the middle.

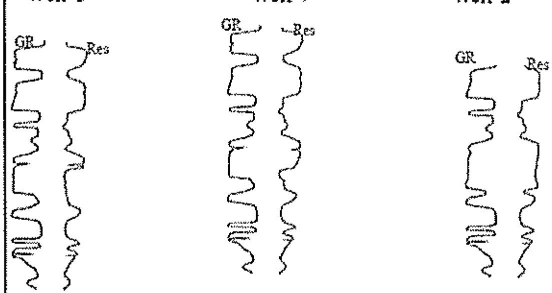
7) In highly faulted area, concentrate down the log to the fault first. Then, correlate up the log to the fault. (FIG. 2)

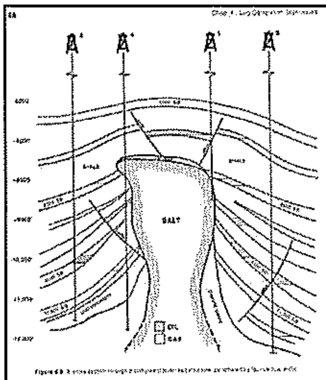
8. Do not force a correlation.

Gamma Ray Log (GR)



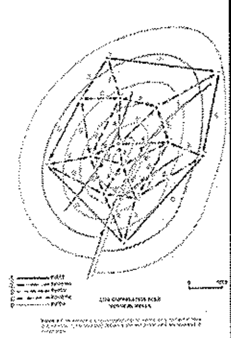
Lateral Continuity ?

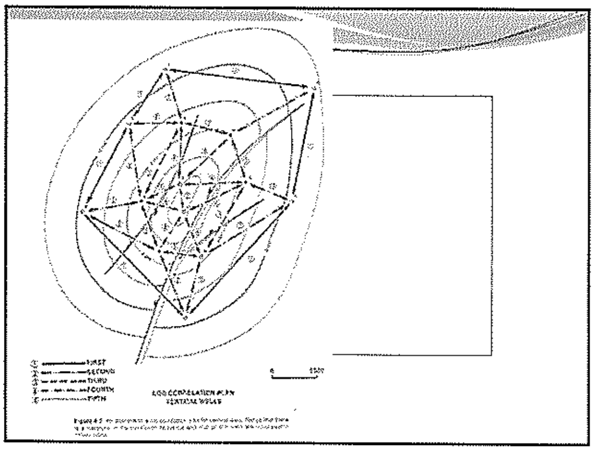


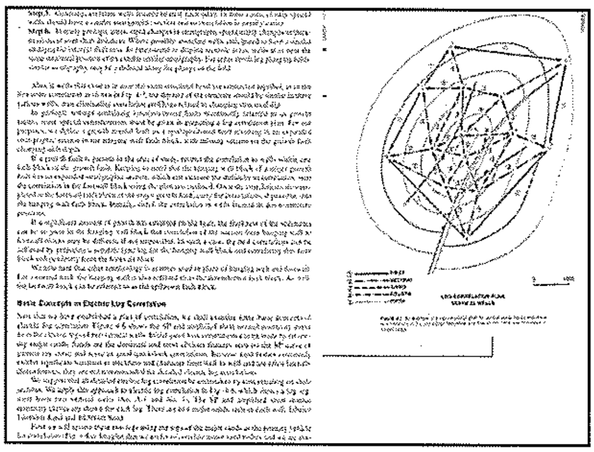


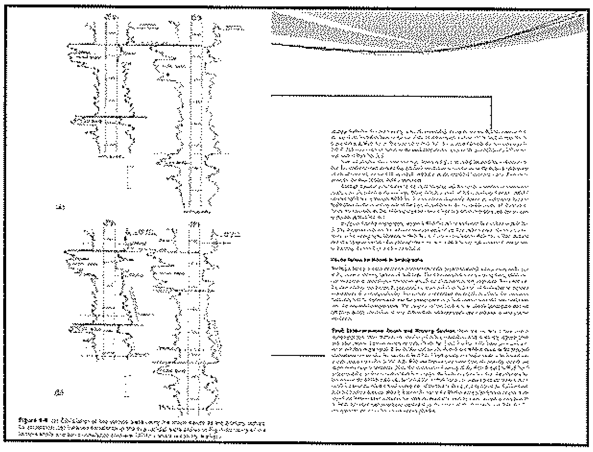
ELECTRIC LOG CORRELATION – VERTICAL WELLS

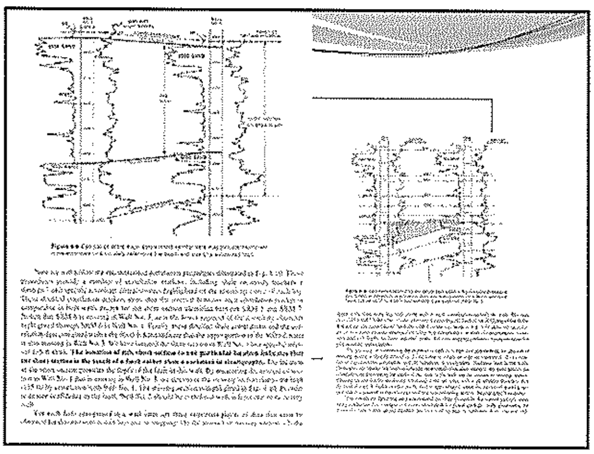
Log Correlation Plan

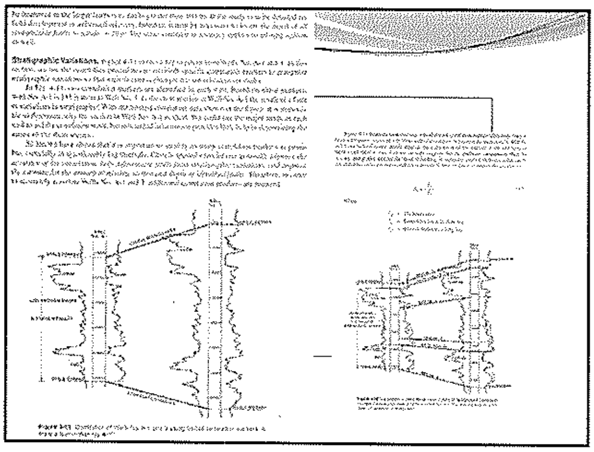


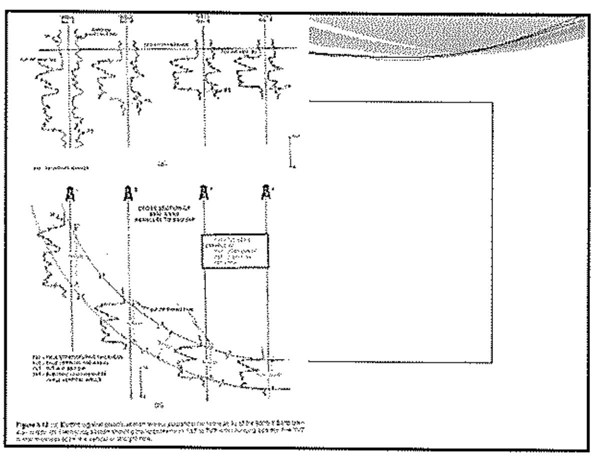


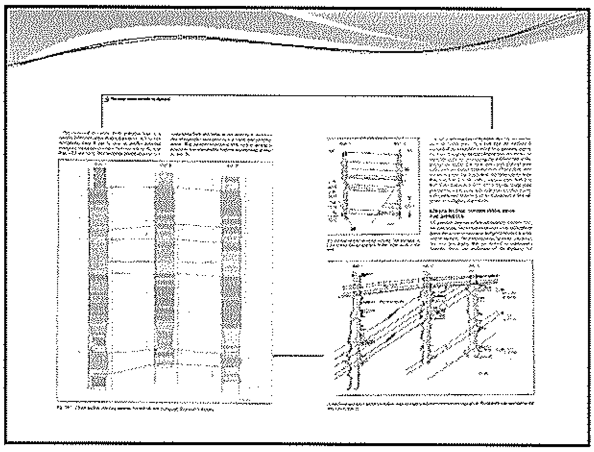


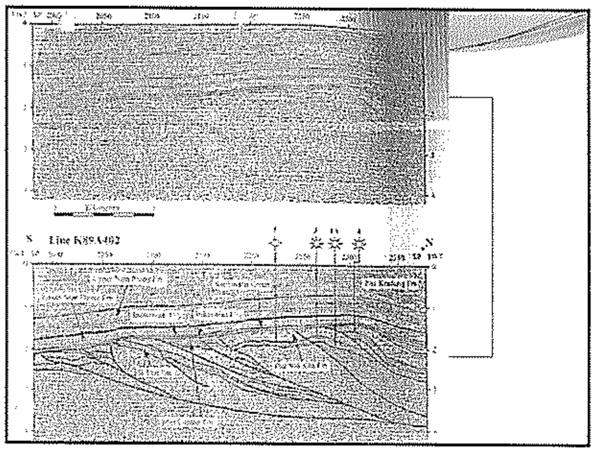








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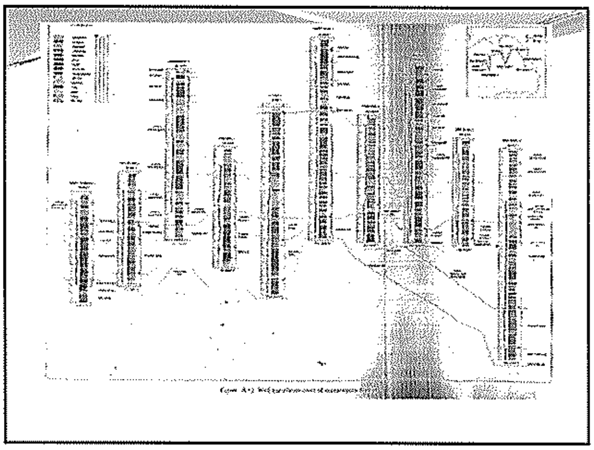
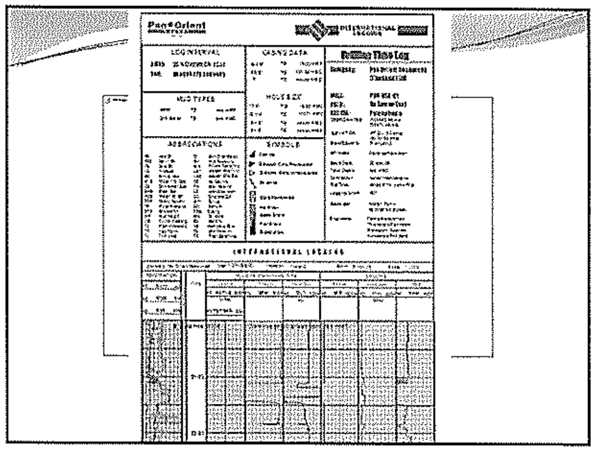
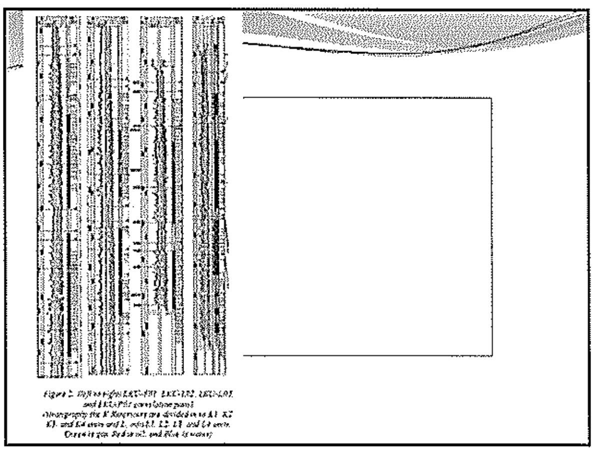



Pan Orient
INTERNATIONAL LOGGING



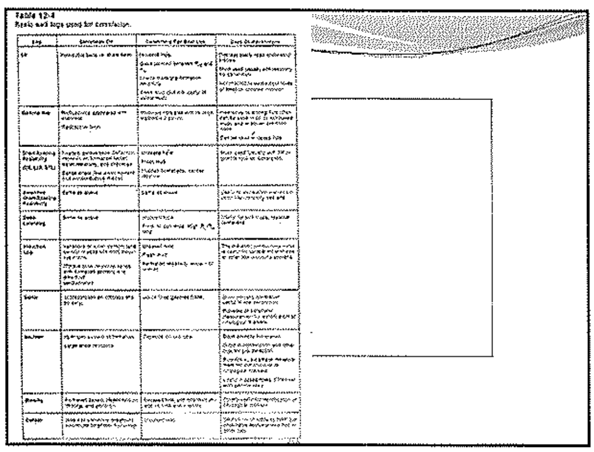


Table 12-4
Basic well logs used for correlation.

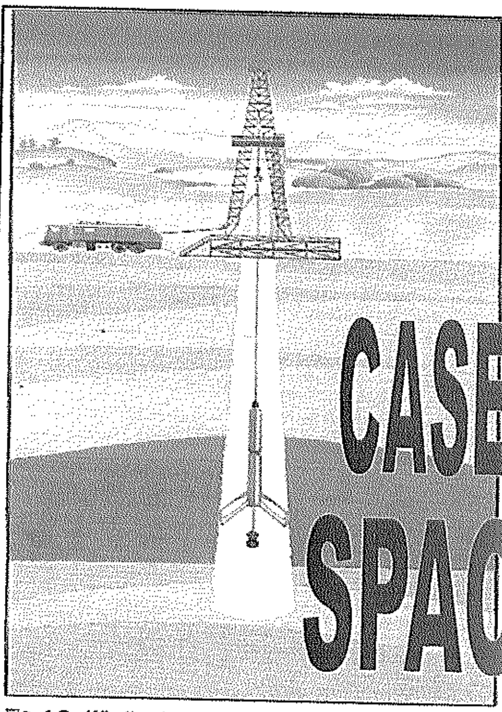


Fig. 1-2—Wireline logging operation.

WELLLOGGING

CHAPTER18

CASED HOLE LOGS SPACIAL LOGS

Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Abnormal Pressure(1 hr.)
Fracture Detection with Well Logs(1 hr.)
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)

Case Hole Logging(3 hrs.)
Special Logs(1 hrs.)

Core & Core Analysis(2 hrs.)

CASED HOLE LOGGING

1. FLUID SATURATION

- Pulsed Neutron logs S_w, S_g, S_o

  วัด Capture Cross Section Σ

  Gas < 10

  Oil $= 21$

  F. Water $= 22.2$

  Salt " $= 40$ to 120

  วัด gamma ที่ Neutron ปล่อยออก.

  (Thermal Decay Time log) $N = N_0 e^{-t/\tau}$

- Carbon-Oxygen logs $\tau = \frac{4550}{\Sigma}$

2. Porosity
   - Compensated Neutron logs
3. Formation Lithology
   - Gamma Ray
   - Spectral Gamma ray
4. Well Integrity log
   - CBL + VDL Acoustic
   - Caliper (Corrosion bow-spring Multiple fingers)
   - Electromagnetic, Electropotential
5. Production log Tools

   วัด Temp., flow rate, density, Type

Cased Hole – Correlation/Evaluation

Gamma Ray	Lithology and correlation Inexpensive. No porosity.	Correlation
Neutron log – single detector	Lithology and correlation Inexpensive. No porosity.	Correlation
Neutron log – dual detector	Porosity. RA source needed, accuracy less than OH log.	Formation Evaluation
Acoustic	Porosity. Limited in cased wells, requires good bonds for accuracy	Formation Evaluation
Pulsed Neutron Capture PNC	Water saturation. Does not work in low or changing salinity, or low porosity	Formation Evaluation
Pulsed Neutron Spectrometry PNS C/O	Water saturation. Does not work well in low porosity	Formation Evaluation
Cased Hole Resistivity	Water Saturation. Salinity dependent, stationary reading, relative deep reading	Formation Evaluation

NEUTRON LIFETIME LOG

NLL (Neutron L.L) Atlas Wireline S.
TDT (Thermal Decay Time) Schlumberger

- used to distinguish gas / oil / Salt water in Cased hole
- Detect G/o/water Contacts
- Hydrocarbon Migration between Zones
- Recovery Efficiency

CAPTURE CROSS SECTION (Σ)

ลด เมื่อ Hydro Carbon content เพิ่ม
เพิ่ม เมื่อ Porosity เพิ่ม
เพิ่ม " water Salinity เพิ่ม

NLL ประกอบไปด้วย

1. Capture Gamma ray measure during 400-600 μs
2. " " " " 700-900 micro S.
3. Monitor
4. Calculate Σ

ADVANCE & SPECIAL DEVICES

- DIP METER
  - HDT (high Resolution Dipmeter T
  - SHDT (Dual Dipmeter) Standa
  - FMS (Formation Micro Scanner)
- FRACTURE DETECTION
  - LSS (Long-Spaced Sonic Array-Sonic)
    Drop in shear indicated Fractur
- Thermal Decay Tool (TDT)
  หา Sw , หา MOHC
- CBL (Cement Bond Log)
- RFT
- PRODUCTION Combination Te
- PIPE ANALYSIS TOOL (PAT)

Cased Hole – Casing/Cement Inspection

Caliper Log	Accuracy depends on number of fingers, speed, tool type.	Casing Inspection
Eddy Current	Inner wall investigation. Shows some smaller flaws, measures ID	Casing Inspection
Flux Leakage	Casing body inspection. Id of inner / outer wall, and body casing problems, not in OBM	Casing Inspection
Ultrasonic	Casing body inspection. Affected by fluids, used in thicker wall pipe (>0.2")	Casing Inspection
Electromagnetic Phase Shift	Casing body inspection. ID and wall thickness, averaging tool may miss small defects	Casing Inspection
Conventional Acoustic	Cement presence. Averaged data, not really useful for most problem identification	Cement Evaluation
Segmented Acoustic	Channels, Bond. 360°, channels and voids, bond under right conditions.	Cement Evaluation
Ultrasonic	Casing and Cement bond. 360°, channels, voids, bond, pipe conditions w/ right application.	Cement Evaluation

Detection of Crossflow

Problem or Information Needed	Rec. Logging Tools	Procedure/Level of Detail
Detection of Crossflow or Underground Blow out	Temperature Survey	Difference in slope of temperature gradient – will detect flow rates down to 25 BPD if liquid and temperatures of fluids are different. Figures on temperature vs. flow distance help estimate water flow in the annulus.
	Noise Log	Best performance of noise logs is with gas flow. Gas flow to about 10 actual ft^3/D (Note – not standard ft^3/day). At very low gas flow rates ($q<400$ actual ft^3/D), gas flow can be estimated from millivolts of noise between the 200-Hz and 600-Hz frequencies: $q = 0.35 (N_{200} - N_{600})$. Where q is the actual gas flow in ft3 and N = noise log cut at that frequency.
	Oxygen Activation Survey	Open hole or channels behind single string. Accuracy is sharply reduced for investigating channels behind two strings (use temp or noise tools).

Cased Hole – Fluid Composition

Capacitance, Fluid Di-elect.	Fluid type - hydrocarbon vs. water.
Fluid Resistivity	Fluid type - hydrocarbon vs. salt water.
Pulsed Neutron Capture	3-phase ID in well, req. homogeneous formation
Gradiomanometers	Fluid type - oil and water, looses resolution in high deviation, limited in high rate and high oil cut.
Fluid Density	Fluid type- oil vs. water, better in high GLR.
Temperature	Fluid entry (zones/leaks) rate/temp limits.
Noise	Leak/zone entry. Channel flow behind pipe, depending on rate.
Fluid Level Survey	Fluid level only, confused by foams, froths and emulsions.
Spinners	Total flow rates and entry/exit points. Deviated wells are a challenge.
Radioactive Tracer Tool	Total flow rates and entry/exit points. Not useful in deviated wells.
Oxygen Activation	Velocity of water phase. Holdup and leak detection.

Location of Cement Top

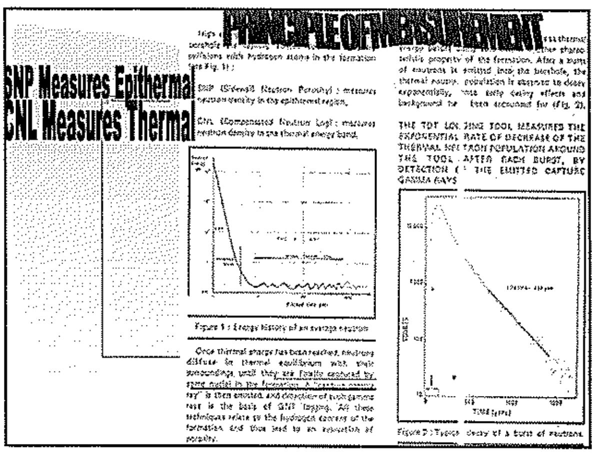
Problem or Information Needed	Rec. Logging Tools	Procedure / Level of Detail
Location of Cement Top	Temperature Survey	OK if run within 12 to 24 hrs of cement job. Little temperature variation with the formation may make cement top difficult to see.
	CBL (cement bond log)	Best results after 3 days or when cement has developed 70%+ of the compressive strength. These tools may be too large for slim hole wells.
	Gravel-pack logging (GR)	Tool response depends on density difference between cement and annular fluid.

Evaluation of Cement Placement and Bond

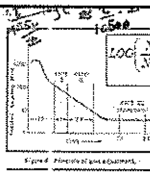
Problem or Information Needed	Rec. Logging Tools	Procedure / Level of Detail
Evaluation of Cement Placement	Open hole caliper	Accuracy depends on caliper and hole roughness and washouts. Caliper tools with more than 4 arms are needed for hole volume measurement accuracy.
	Sweeps with markers after running casing	Sweeps give decent estimates of hole volume, but sweeps may not reach all of the annular space in uncentralized cased holes. Useful for swept hole % analysis.
	Temperature Survey	OK if run within 12 to 24 hrs of cement job. Little temperature variation with the formation may make cement top difficult to see.
	Gravel Pack Log	Good if fluid density difference greater than 0.3 gm/cc (0.13 lb/bbl). Could run before and after cement for background data.
	CBL – both regular and segmented	Semi-quantitative contact measurement of pipe/cement and cement/formation. Affected by casing pressure and tool calibration.

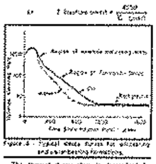
Casing Inspection

Problem or Information Needed	Rec. Logging Tools	Procedure / Level of Detail
Detection of casing wear from drilling	E-line calipers	Multi-arm calipers generally good, but slick line calipers may rotate and "over-report" the bad spots.
	EM – eddy current tool that measures wall thickness	Highly accurate if the hole is filled with a non conductive fluid.
	Acoustic wall thickness tool	Qualitative indicators of wear (thickness numbers are not very accurate)



$$LOG\left(\frac{N}{N_o}\right) = -\frac{t}{\tau}\log(e) = -\frac{t}{\frac{4550}{\Sigma}}*(1/2.303) = -\frac{\Sigma t}{10500}$$

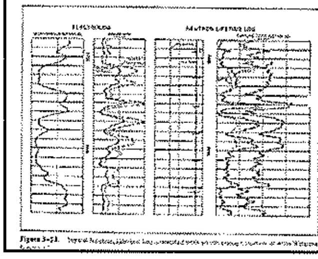




CAPTURE CROSS SECTION

$$N = N_o * e^{-\frac{t}{\tau}}$$

$$LOG\left(\frac{N}{N_o}\right) = -\frac{t}{\tau}\log(e) = -\frac{t}{\frac{4550}{\Sigma}}*(1/2.303) = -\frac{\Sigma t}{10500}$$



INTERPRETATION BASES

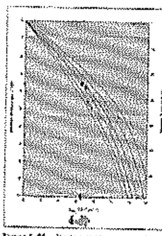
$$\Sigma_{log} = (1-\phi)\Sigma_{ma} + \phi S_w \Sigma_w + \phi(1-S_w)\Sigma_h \quad (9.8)$$

Solving Eq. 9.8 for water saturation gives

$$S_w = \frac{(\Sigma_{log} - \Sigma_{ma}) - \phi(\Sigma_h - \Sigma_{ma})}{\phi(\Sigma_w - \Sigma_h)}$$

For a clean water-bearing formation, Eq. 9.8

$$\Sigma_{log} = (1-\phi)\Sigma_{ma} + \phi\Sigma_w$$



The Shale Reference Method.

The Gulf Coast Method.

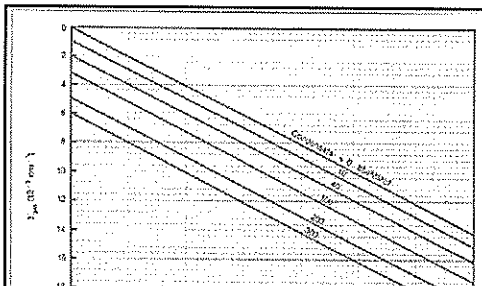
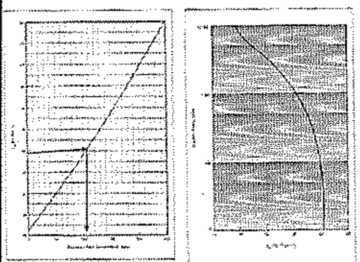
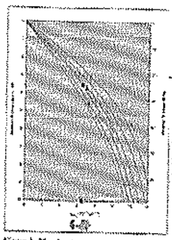


Figure 3-76. Chart for determining Σ_h when Σ_{CH_4} and condensate yield are known (courtesy of Atlas Wireline Services).

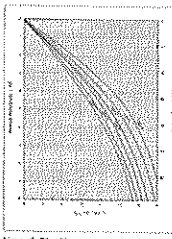


QUALITATIVE INTERPRETATION



The Shale Reference Method.

The Gulf Coast Method.



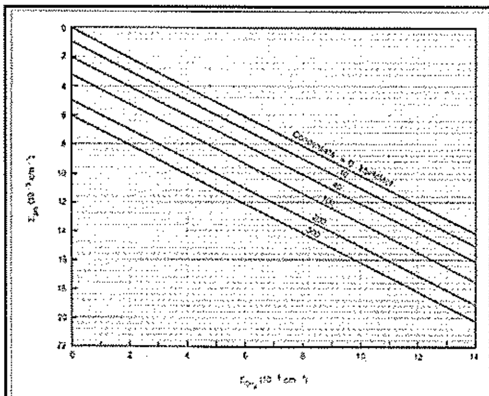


Figure 3–76. Chart for determining Σ_c when Σ_{w} and condensate yield are known (courtesy of Atlas Wireline Services).

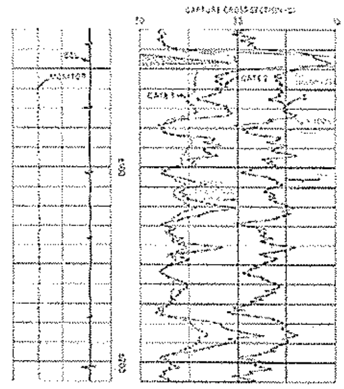
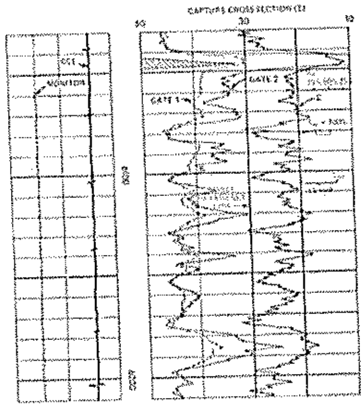
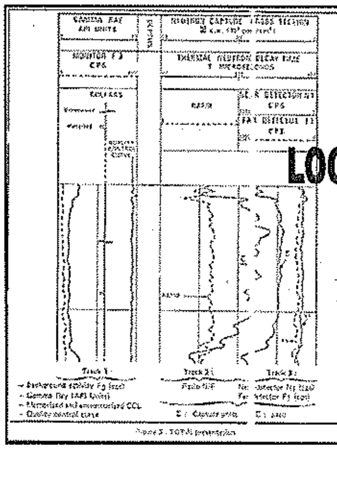


Figure 3–77. Presentation of the Shale Reference method (courtesy of Atlas Wireline Services).





LOG PRESENTATION

F1 =Far detector

N1 =Near detector

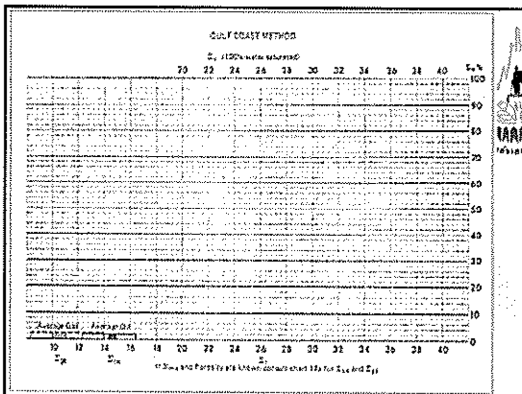
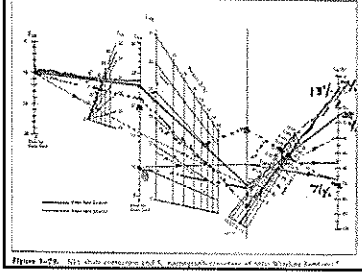


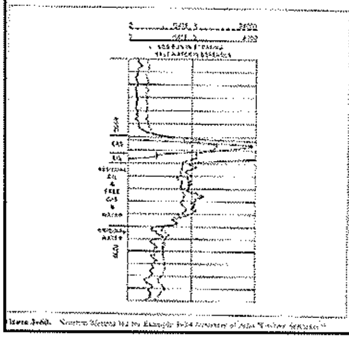
Figure 3-78. Chart for qualitative analysis of NLL using the Gulf Coast method (courtesy of Atlas Wireline Services).

QUANTITATIVE ANALYSIS—CLEAN FORMATIONS

$$\Sigma t = \phi \Sigma_h + \Sigma_r$$

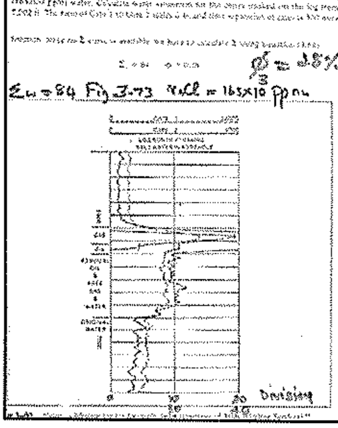
QUANTITATIVE ANALYSIS—SHALY FORMATIONS





$\Sigma_w = 84$ Fig 3-73 NaCl = 165x10 ppm

$\phi = 28\%$



1. Find Σo from water zone

$$\Sigma = \frac{10{,}000}{\Delta t} \log_{10} \frac{N_1}{N_2}$$

2. Find Σmatrix from

$$\Sigma_{ma} = \frac{\Sigma_t - \phi \Sigma_w}{1 - \phi}$$

3. Calculate Σt(log) interpretation zone

$$\Sigma = \frac{10{,}000}{\Delta t} \log_{10} \frac{N_1}{N_2}$$

3. Calculate Sw from

Solving Eq. 9.8 for water saturation gives

$$S_w = \frac{(\Sigma_{log} - \Sigma_{ma}) - \phi(\Sigma_h - \Sigma_{ma})}{\phi(\Sigma_w - \Sigma_h)}$$

For a clean water-bearing formation, Eq. 9.8

$$\Sigma_{log} = (1 - \phi)\Sigma_{ma} + \phi\Sigma_w$$

Using Equation (3-64), S_w is

$$S_w = \frac{19 - 10 + 0.27(10 - 9) + 0.11(10 - 37)}{0.27(60 - 9)}$$

$\approx 7\%$

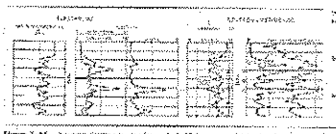
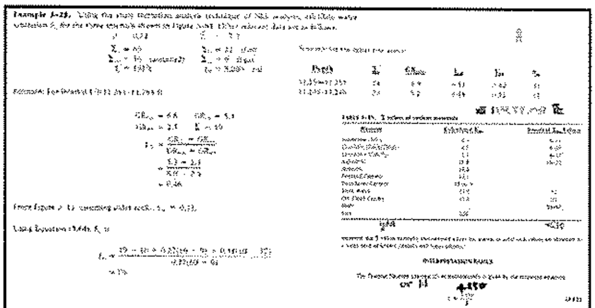


Figure 3-81. Neutron lifetime log for Example 3-25 (courtesy of Atlas Wireline Services).



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$\approx 7\%$

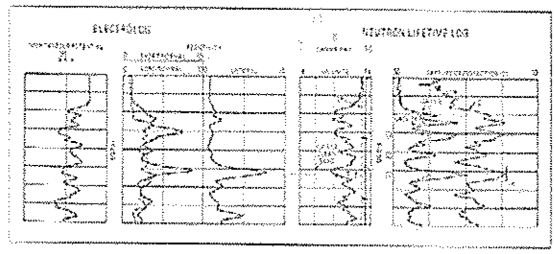


Figure 3-81. Neutron lifetime log for Example 3-25 (courtesy of Atlas Wireline Services).

9.6 Pulsed Neutron Tools

The pulsed neutron tool periodically emits a burst of high-energy (14-MeV) neutrons and then measures the time required for a certain fraction of the neutrons to be absorbed by the formation. Of the common earth elements, chlorine is by far the strongest neutron absorber. In clean formations, the tool response is determined primarily by the chlorine present in the formation water. The tool response can be used qualitatively to differentiate between water-, oil-, and gas-bearing formations. It can also be used quantitatively to estimate water saturation. Because the tool can be run in cased holes, it has become an important device for evaluating old wells and monitoring new wells.

In a homogeneous medium, the decay of thermal neutrons is theoretically an exponential function of time:

$$n = n_0 e^{-t/\tau}, \qquad (9.5)$$

where n_0 = number of thermal neutrons at a time t_0 following neutron burst, n = number of thermal neutrons at time t measured from time t_0, and τ = thermal decay time.

With Schlumberger's Thermal Decay Time (TDT[SM]) tool, τ is defined as the time required for the number of neutrons to diminish to a fraction $1/e$, which is about 37%. The thermal decay time depends on the composite capture cross section of the formation, Σ. Σ and τ are related by[16]

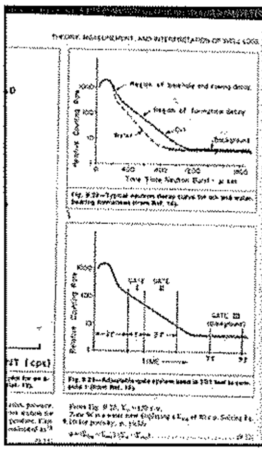


Fig. 9.22—Typical neutron decay curve for oil- and water-bearing formations (from Ref. 16).

Fig. 9.23—Adjustable-gate system used in TDT tool to compute τ (from Ref. 16).

$$\Sigma = 4.55/\tau. \qquad (9.6)$$

With Atlas Wireline's Neutron Lifetime Log (NLL[SM]), τ is defined as the time required for a 50% decay.[17] In this case,

$$\Sigma = 3.15/\tau. \qquad (9.7)$$

Fig. 9.22 is a typical curve of neutron decay vs. time for saltwater- and oil-bearing sands. Fig. 9.23 illustrates the method the TDT tool uses to compute τ. After emission of the neutron bursts and a time sufficiently long for the borehole effect to become negligible, the detector circuit is switched on, and gamma rays are counted during three time intervals or "gates."[16] The background, which consists of natural radioactivity and long-lived induced radioactivity, is measured during the third gate and subtracted from the readings of the first and second gates. The two net readings are combined to compute τ and Σ from Eqs. 9.5 and 9.6. To ensure that the counts of the first two gates are within the region of formation decay, the tool automatically adjusts the timing of the gates so that all three are related to τ, as shown in Fig. 9.23.

Fig. 9.24 shows an example of early TDT logs. The Σ and τ curves are recorded on the combined Tracks 2 and 3. The dotted curve is a quality-control curve. This log was run in 1978 through a clean gas-bearing formation. The log clearly shows the contrast in Σ between the gas and water zones. This contrast reflects the change in chlorine content. The gas/water contact is at 10,084 ft. The initial gas/water contact indicated by the openhole resistivity log recorded in 1972 was at 10,138 ft. This is a case of a strong waterdrive reservoir.

The measured capture cross section, Σ_{log}, is related to the constituents of the formation. For a clean, porous formation containing water and hydrocarbon,[15]

$$\Sigma_{log} = (1-\phi)\Sigma_{ma} + \phi S_w \Sigma_w + \phi(1-S_w)\Sigma_h. \qquad (9.8)$$

Fig. 9.20—Example of dual-porosity CNL (from Ref. 15).

where Σ_{ma}, Σ_w, and Σ_h are the capture cross sections of rock matrix, water, and hydrocarbon, respectively.

Solving Eq. 9.8 for water saturation gives

$$S_w = \frac{(\Sigma_{log} - \Sigma_{ma}) - \phi(\Sigma_h - \Sigma_{ma})}{\phi(\Sigma_w - \Sigma_h)}. \qquad (9.9)$$

For a clean water-bearing formation, Eq. 9.8 reduces to

$$\Sigma_{log} = (1-\phi)\Sigma_{ma} + \phi\Sigma_w. \qquad (9.10)$$

Water capture cross section, Σ_w, is primarily salinity-dependent. Fig. 9.25 shows Σ_w as a function of the total sodium chloride content at temperatures of 75 and 200°F. Formation water may contain elements other than chlorine and sodium. Only boron and lithium are important in the interpretation because of their large capture cross sections.[15] Equivalent NaCl salinity may be computed by adding to the parts per million of the chloride ion 80 times the parts per million of boron and 11 times the parts per million of lithium and then multiplying this sum by 1.65 before entering it into Fig. 2.25.

Σ_h for oil can be derived from Fig. 9.26 when API gravity and the solution GOR are known. A value of 21 c.u. (1 c.u. = 10^{-3} cm²/cm³) is a good approximation of most field conditions.[15]

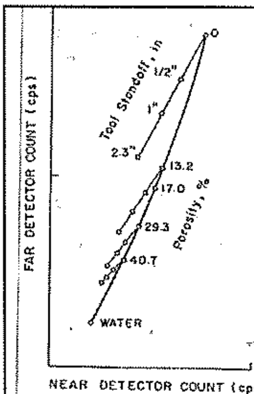


Fig. 9.21—Epithermal neutron spine-and-ribs plot for an 8-in. borehole and limestone formations (from Ref. 15).

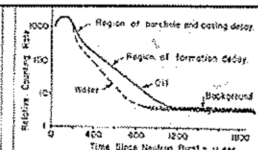


Fig. 9.22—Typical neutron decay curve for oil- and water-bearing formations (from Ref. 16).

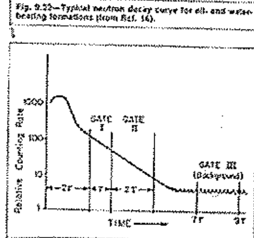


Fig. 9.23—Adjustable-gate system used in TDT tool to compute τ (from Ref. 16).

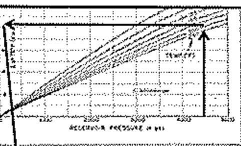
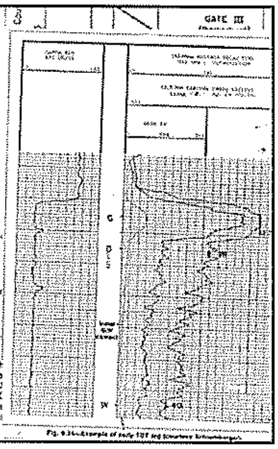


Fig. 9.27—Methane capture cross section, Σ_{CH_4}, as a function of pressure and temperature (from Ref. 16).



$\Sigma_g = \Sigma_{CH_4}(0.23 + 1.4\gamma_g)$ .... (9.11)

where γ_g is the gas specific gravity.

Average values of matrix capture cross section recommended for use are 9, 12, and 8 c.u. for sandstones, limestones, and dolomite, respectively.[18]

Example 9.5. Estimate the gas saturation in the unswept and swept Zones G and D of the sand formation shown in Fig. 9.24. The following data are also available.

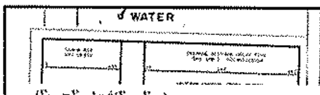
Formation temperature, °F	200
Reservoir pressure (at the time the TDT log was run), psia	4,500
Water equivalent salinity, ppm	250,000
Gas specific gravity	0.65

Solution. Using Eq. 9.11 and Fig. 9.27 yields

$\Sigma_{CH_4} = 8.1$ c.u

and $\Sigma_g = 8.1(0.23 + 1.4 \times 0.65)$

$= 9.2$ c.u



$$S_w = \frac{(\Sigma_{log} - \Sigma_{ma}) - \phi(\Sigma_h - \Sigma_{ma})}{\phi(\Sigma_w - \Sigma_h)} \quad (9.9)$$

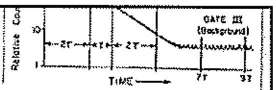


Fig. 9.22—Adjustable-gate system used in TDT tool to compute τ (from Ref. 16).

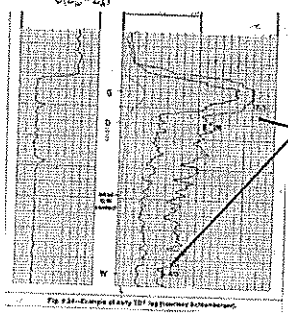


Fig. 9.24—Example of early TDT log (courtesy Schlumberger).

From Fig. 9.26, $\Sigma_w = 120$ c.u.

Zone W is a water zone displaying a Σ_{log} of 40 c.u. Solving Eq. 9.10 for porosity, ϕ, yields

$\phi = (\Sigma_{log} - \Sigma_{ma})/(\Sigma_w - \Sigma_{ma})$. .... (9.12)

Taking $\Sigma_{ma} = 9$ c.u. yields

$\phi = (40 - 9)/(120 - 9) = 0.28$.

S_w can now be estimated from Eq. 9.9. For the unswept Zone G where $\Sigma_{log} = 12.5$ c.u.,

$$S_w = \frac{(12.5 - 9) - 0.28(9.2 - 9)}{0.28(120 - 9.2)} = 0.11 \text{ or } 11\%,$$

and for the swept Zone D where $\Sigma_{log} = 28$ c.u.,

$$S_w = \frac{(28 - 9) - 0.28(9.2 - 9)}{0.28(120 - 9.2)} = 0.61 \text{ or } 61\%.$$

New generations of the TDT tool (e.g., TDT-K and TDT-M) have increased neutron output, modified techniques for measuring and recording decay time, and a second detector.[20,21] The second detector provides more information (Fig. 9.28). In addition to the Σ curve, the log displays an overlay of the count rates of the far and near detectors (Curves F1 and N1, respectively). Also displayed is a ratio curve derived from the count rate of the two detectors.

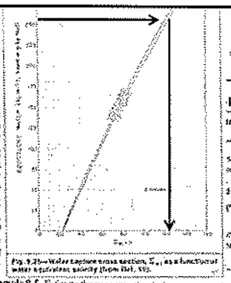
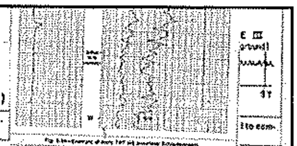


Fig. 9.25—Water capture cross section, Σ_w, as a function of water equivalent salinity (from Ref. 16).



Example 9.5. Estimate the gas saturation in the unswept and swept Zones G and D of the sand formation shown in Fig. 9.24. The following data are also available.

Formation temperature, °F	200
Reservoir pressure (at the time the TDT log was run), psia	4,500
Water equivalent salinity, ppm	250,000
Gas specific gravity	0.65

Solution. Using Eq. 9.11 and Fig. 9.27 yields

$\Sigma_{CH_4} = 8.1$ c.u.

and $\Sigma_g = 8.1(0.23 + 1.4 \times 0.65)$

$= 9.2$ c.u.

From Fig. 9.26, $\Sigma_w = 120$ c.u.

Zone W is a water zone displaying a Σ_{log} of 40 c.u. Solving Eq. 9.10 for porosity, ϕ, yields

$\phi = (\Sigma_{log} - \Sigma_{ma})/(\Sigma_w - \Sigma_{ma})$. .... (9.12)

Taking $\Sigma_{ma} = 9$ c.u. yields

$\phi = (40 - 9)/(120 - 9) = 0.28$.

S_w can now be estimated from Eq. 9.9. For the unswept Zone G where $\Sigma_{log} = 12.5$ c.u.,

$$S_w = \frac{(12.5 - 9) - 0.28(9.2 - 9)}{0.28(120 - 9.2)} = 0.11 \text{ or } 11\%,$$

and for the swept Zone D where $\Sigma_{log} = 28$ c.u.,

$$S_w = \frac{(28 - 9) - 0.28(9.2 - 9)}{0.28(120 - 9.2)} = 0.61 \text{ or } 61\%.$$

New generations of the TDT tool (e.g., TDT-K and TDT-M) have increased neutron output, modified techniques for measuring and recording decay time, and a second detector.[20,21] The second detector provides more information (Fig. 9.28). In addition to the Σ curve, the log displays an overlay of the count rates of the far and near detectors (Curves F1 and N1, respectively). Also displayed is a ratio curve derived from the count rate of the two detectors.

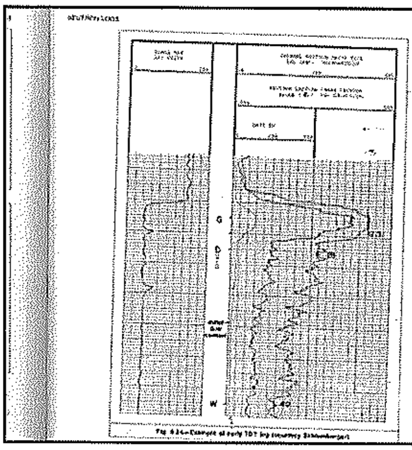


Fig. 9.24—Example of early TDT log (courtesy Schlumberger).

Fig. 9.24—Example of early TDT log (courtesy Schlumberger).

The background curve labeled Curve F3 is recorded for quality-control purposes.

The scales used to record Curves F1 and N1 are selected so that the two curves superimpose in clean water-bearing zones (Zone A). The two curves separate slightly in oil zones (Zone B) but show a large separation in gas zones (Zone C). The separation between both curves and its magnitude result from the difference in hydrogen atom density (number of atoms per unit volume) between water, oil, and gas.

The ratio curve value is derived from the count rates of Curves N1 and F1 corrected for background radiations.[20] The ratio and Σ values permit a quick quantitative evaluation of a formation that does not require the knowledge of Σ_w, Σ_{ma}, and Σ_h. The evaluation method uses experimentally constructed crossplots of Σ vs. ratio similar to those shown in Fig. 9.29.

Entering the appropriate crossplot with the zone's Σ and ratio values provides a water salinity, C, and porosity, ϕ, values. These values approximate the true values only if the zone is clean and water-bearing. In hydrocarbon zones, the crossplot yields apparent water salinity, C_a, and apparent porosity, ϕ_a. In oil zones, oil appears like fresh water; this results in an apparent water salinity that is less than the true one. A quick method for estimating the water saturation is to use the water-salinity-index ratio:

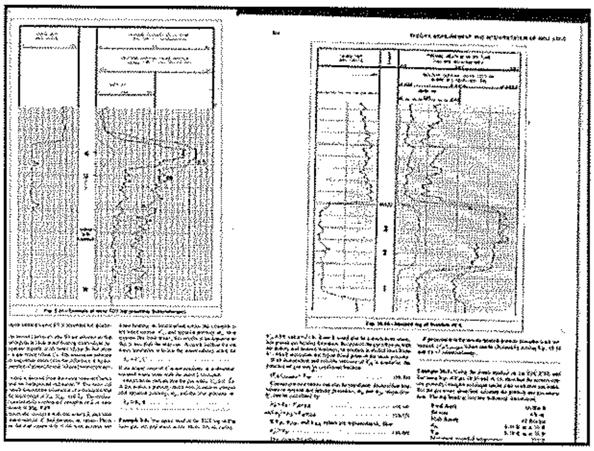
$S_w = C_a/C$. .... (9.13)

If the actual value of C is not available, it is obtained from an associated water zone with the ratio/Σ crossplot.

Observations indicate that for gas zones, $C_a \geq C$. To estimate S_w in gas zones, a porosity-index ratio is used to compare the crossplot apparent porosity, ϕ_a, and the true porosity, ϕ:

$S_w = \phi_a/\phi$. .... (9.14)

Example 9.6. The upper sand of the TDT log of Fig. 9.30 contains gas, oil, and water zones. Here, 5½-in. casing is cemented



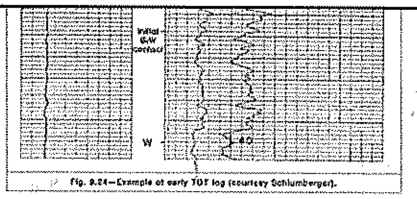


Fig. 9.24—Example of early TDT log (courtesy Schlumberger).

The background curve labeled Curve F3 is recorded for quality-control purposes.

The scales used to record Curves F1 and N1 are selected so that the two curves superimpose in clean water-bearing zones (Zone A). The two curves separate slightly in oil zones (Zone B) but show a large separation in gas zones (Zone C). The separation between these curves and its magnitude result from the difference in hydrogen atom density (number of atoms per unit volume) between water, oil, and gas.

The ratio curve value is derived from the count rates of Curves N1 and F1 corrected for background radiations.[20] The ratio and Σ values permit a quick quantitative evaluation of a formation that does not require the knowledge of Σ_w, Σ_{ma}, and Σ_h. The evaluation method uses experimentally constructed crossplots of Σ vs. ratio similar to those shown in Fig. 9.29.

Entering the appropriate crossplot with the zone's Σ and ratio values provides a water salinity, C, and porosity, φ, values. These values approximate the true values only if the zone is clean and water-bearing. In hydrocarbon zones, the crossplot yields apparent water salinity, C_a, and apparent porosity, ϕ_a. In oil zones, oil appears like fresh water; this results in an apparent water salinity that is less than the true one. A quick method for estimating the water saturation is to use the water-salinity-index ratio:

$$S_w \approx C_a/C. \qquad (9.13)$$

If the actual value of C is not available, it is obtained from an associated water zone with the ratio/Σ crossplot.

Observations indicate that for gas zones, $C_a \cong C$. To estimate S_w in gas zones, a porosity-index ratio is used to compare the crossplot apparent porosity, ϕ_a, and the true porosity, φ:

$$S_w \approx \phi_a/\phi. \qquad (9.14)$$

Example 9.6. The upper sand of the TDT log of Fig. 9.30 contains gas, oil, and water zones. Here, 5½-in. casing is cemented

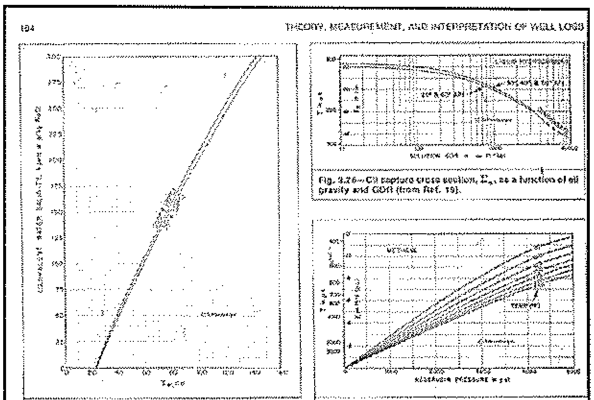


Fig. 9.26—Water capture cross section, Σ_w, as a function of water equivalent salinity (from Ref. 19).

Fig. 9.26—Oil capture cross section, Σ_o, as a function of oil gravity and GOR (from Ref. 19).

Fig. 9.27—Methane capture cross section, Σ_{CH_4}, as a function of pressure and temperature (from Ref. 19).

Example 9.6. The upper sand of the TDT log of Fig. 9.30 contains gas, oil, and water zones. Here, 5½-in. casing is cemented in an 8¾-in. hole, a 2⅞-in. tubing is present, and the annulus is filled with salt water.

a. Determine the depth of the gas/oil and oil/water contacts.

b. For the three zones indicated on the log, estimate the water saturation, assuming that the sand displays a constant porosity value.

Solution.

a. The top zone displays a separation of Curves F1 and N1 that is consistent with the presence of gas. The separation disappears around 6,314 ft, which is the gas/oil contact. In general, oil zones indicate a Σ value higher than that of associated water zones. The oil/water contact can then be placed at a depth of 6,352 ft.

b. The table below lists the log reading and ϕ_a and n_a obtained from Crossplot C of Fig. 9.29.

Zone	Σ (c.u.)	Ratio	ϕ_a (%)	C_a (1,000 ppm)
Gas	18	2.0	13	150
Oil	18.5	2.9	28	60
Water	32	3.7	35	145

The water-saturation values in the gas and oil zones are estimated from Eqs. (9.14) and (9.13), respectively.

For the gas zone, $S_w \cong 13/35 = 0.37$, and for the oil zone, $S_w \cong 60/145 = 0.41$.

$$S_w \approx C_a/C. \quad \text{oil} \qquad (9.13)$$

If the actual value of C is not available, it is obtained from an associated water zone with the ratio/Σ crossplot.

Observations indicate that for gas zones, $C_a \cong C$. To estimate S_w in gas zones, a porosity-index ratio is used to compare the crossplot apparent porosity, ϕ_a, and the true porosity, φ:

$$S_w \approx \phi_a/\phi. \quad \text{gas} \qquad (9.14)$$

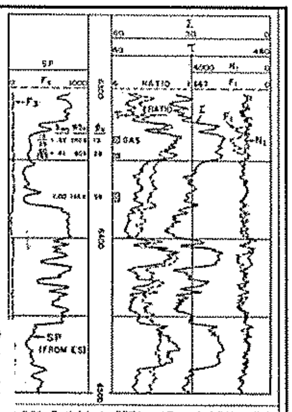


Fig. 9.30—Dual-detector TDT log of Example 9.6 (from Ref. 20).

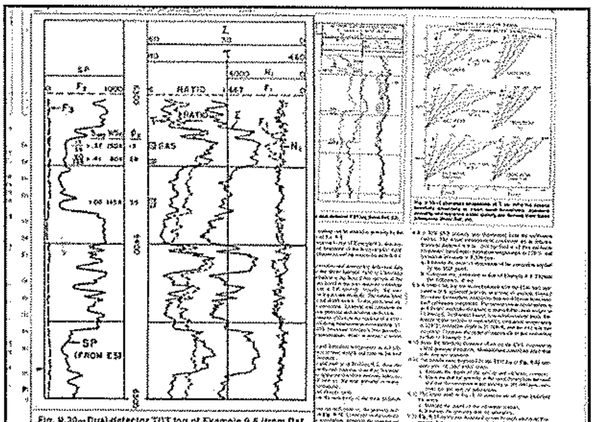
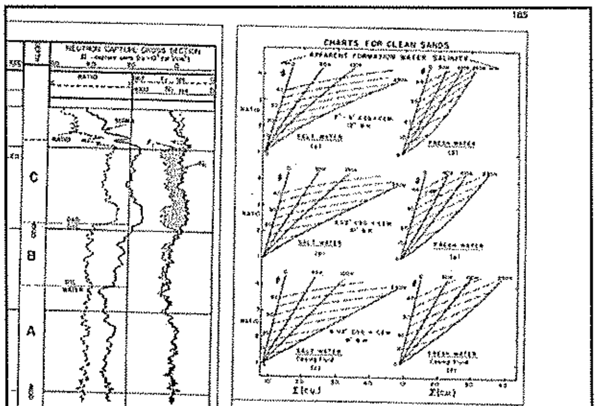
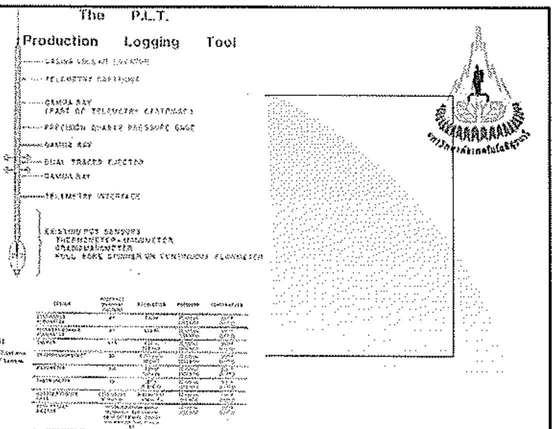


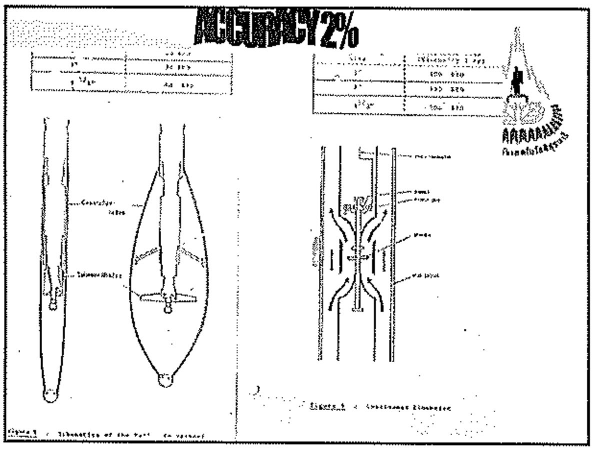
Fig. 9.30—Dual-detector TDT log of Example 9.6 (from Ref. 20).

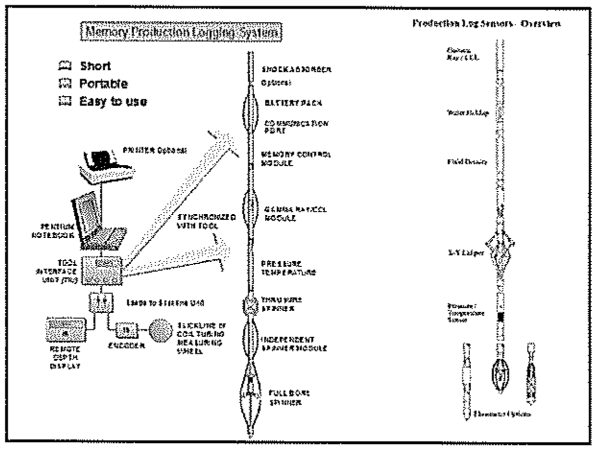


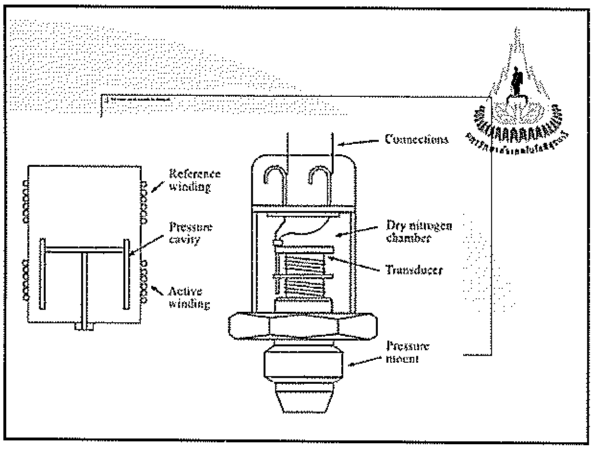
...of a dual-detector TDT log (from Ref. 22).

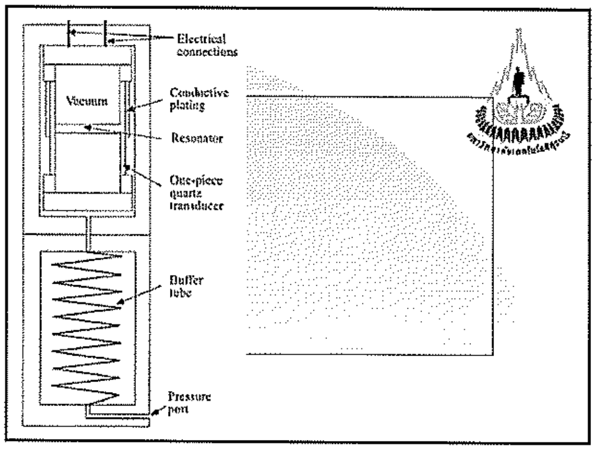
Fig. 9.29—Laboratory crossplots of Σ vs. ratio for several borehole situations in clean sand formations. Apparent porosity and apparent water salinity are derived from these crossplots.

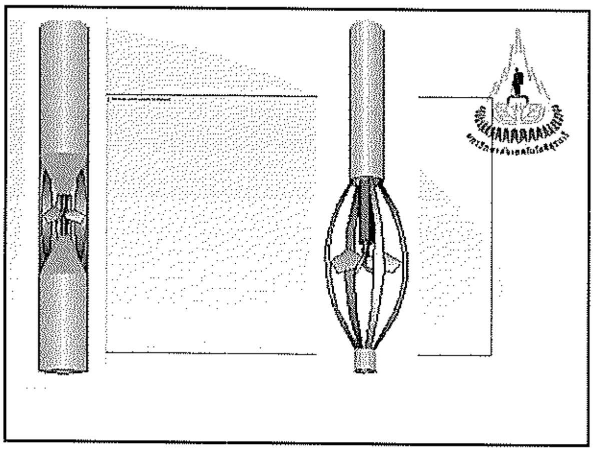


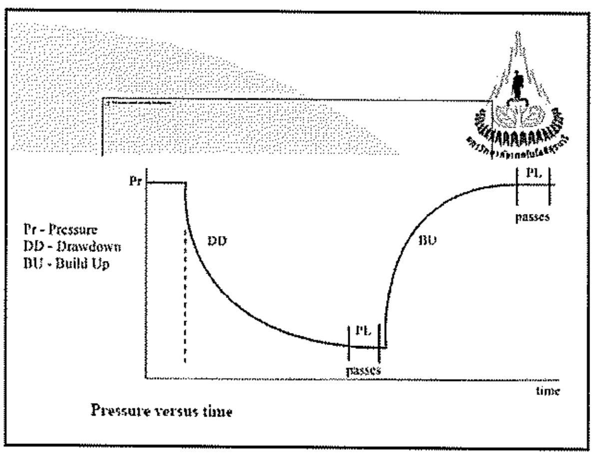

ACCURACY 2%

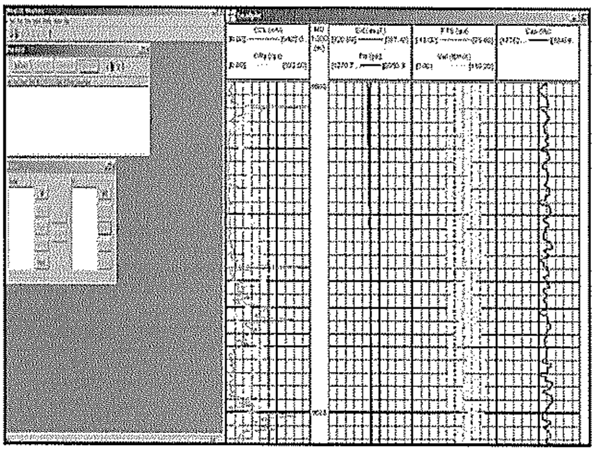

Memory Production Logging System
Short
Portable
Easy to use
SHOCK ABSORBER
Optional
BATTERY PACK
COMMUNICATION PORT
MEMORY CONTROL MODULE
PRINTER Optional
PENTIUM NOTEBOOK
SYNCHRONIZED WITH TOOL
GAMMA RAY/CCL MODULE
TOOL INTERFACE UNIT (TIU)
PRESSURE TEMPERATURE
THRU BORE SPINNER
REMOTE DEPTH DISPLAY
ENCODER
INDEPENDENT SPINNER MODULE
FULL BORE SPINNER
Production Log Sensors - Overview
X-Y Caliper

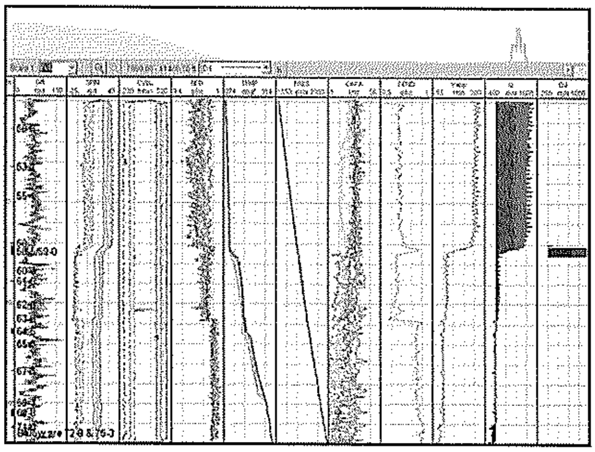

Connections
Reference winding
Pressure cavity
Active winding
Dry nitrogen chamber
Transducer
Pressure mount


Electrical connections
Vacuum
Conductive plating
Resonator
One-piece quartz transducer
Buffer tube
Pressure port




Pr
PL
passes
Pr - Pressure
DD - Drawdown
BU - Build Up
DD
BU
PL
passes
time
Pressure versus time





...2—CORE POROSITY AND NEUTRON LOG READING FROM A 7-in. CASED HOLE, ...STONE, KELLY-SNYDER FIELD (from Ref. 10)

... Porosity (%)	Neutron Log Reading (standard units)
1	0.662
2	0.600
3	0.560
4	0.535
5	0.513
6	0.497
7	0.481
8	0.470
9	0.460
10	0.450
11	0.440
12	0.432
13	0.426
14	0.419
15	0.412
16	0.405
17	0.400
18	0.395
19	0.390
20	0.389
25	0.365
30	0.347

...ore gas injection. Run 2 was made several months ... injection started. Estimate the gas saturation in the ... vicinity. The injected gas is mostly methane. For... mperature and pressure are 60°F and 500 psia, re... ...

...ure

...fficients in Eq. 9.2
...nity, ppm
...ption coefficient of thermal neutrons

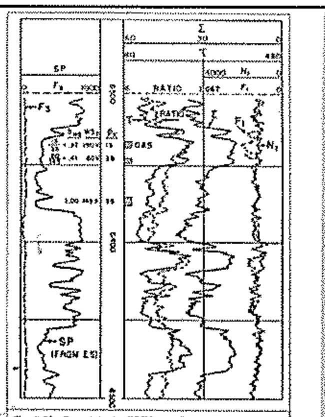
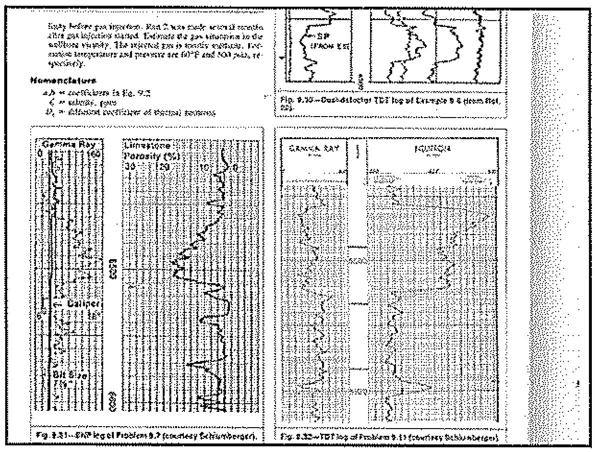


Fig. 9.30—Dual-detector TDT log of Example 9.6 (from Ref. 20).



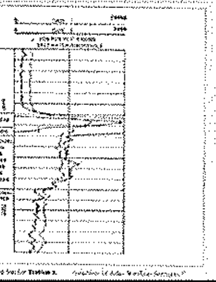
434350 WELL LOGGING 4(3-3-8) (1/2554)

HW NO.12 Due Date Friday 22 March 2013 Cased Hole Log Interpretation.

Figure 1 is an early NLL over a zone of high porosity (28%) and high salinity (170,000 ppm) water. Calculate water saturation for the zone marked on the log from 6,996 to 7,002 ft. The ratio of gate 1 to 2 scales is 10, and time separation of gates is 250 microseconds (see Figure 7-73 to find Σ.)

1. Using the daily formation analysis technique of NL analysis, calculate water saturation S_w for the three intervals (11,261-11,264, 11,250-11,253, and 11,246-11,249 ft) shown in Figure 2. Other relevant data are as follows:

$\phi = 0.25$, $\Sigma_{ma} = 40$, $\Sigma_w = 60$, $\Sigma_h = 22$ if oil, ... if gas, $\Sigma_{sh} = 10$ (assumed), $Tf = 190°F$, $P_f = 5{,}000$ psi



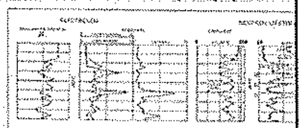


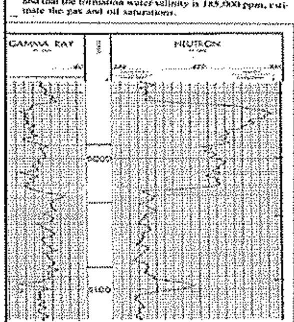
Figure 2.

The middle sand displayed by the TDT log of Fig. 9.32 contains gas, oil, and water zones.

a. Indicate the depth of the gas/oil and oil/water contacts.
b. Knowing that the porosity is the same throughout the sand and that the formation water salinity is 185,000 ppm, estimate the gas and oil saturations.

2. The lower sand in Fig. 9.30 contains an oil zone underlaid by water.

a. Indicate the depth of the oil/water contact.
b. Estimate the porosity and oil saturation.



...g. 9.32—TDT log of Problem 9.11 (courtesy Schlumberger).

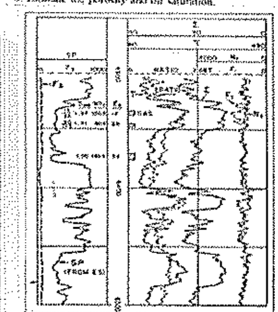


Fig. 9.30—Dual-detector TDT log of Example 9.6 (from Ref. 20).

...lem 9.11 a. Gas/oil contact at 9,050 ft.
Oil/water contact at 9,054 ft.
b. The gas and oil saturation is approximately ...

Problem 9.12 a. The oil/water contact is at 6,480 ft.
b. $\phi \approx 25\%$, $S_o \approx 50\%$.

HW NO.13 Due Date Friday 29 March 2013
Dip Meter, Log Correlation and Core Analysis

1. Draw the arrows in the true dip angle chart for the Figure 1-3.

True Dip Angle

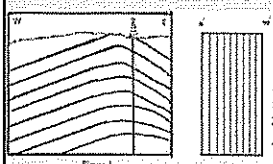


Figure 1.

True Dip Angle

True Dip Angle

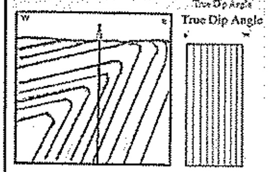


Figure 2

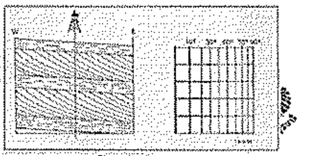


Figure 3.

2. Correlate the logs on the Figure 4

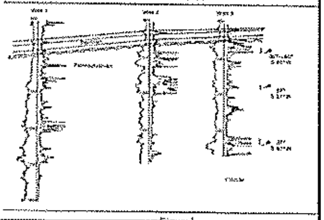
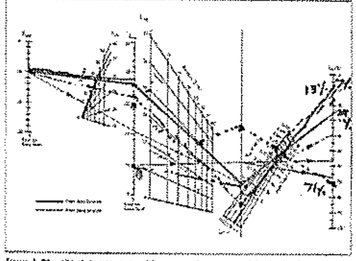


Figure 4

QUANTITATIVE ANALYSIS—SHALY FORMATIONS



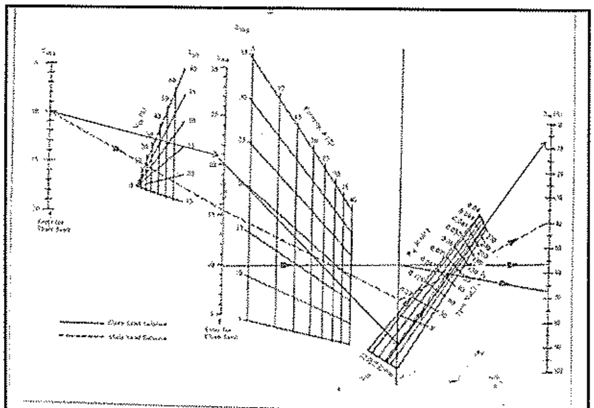


Figure 3–79. NLL shale correction and S_w nomograph (courtesy of Atlas Wireline Services).

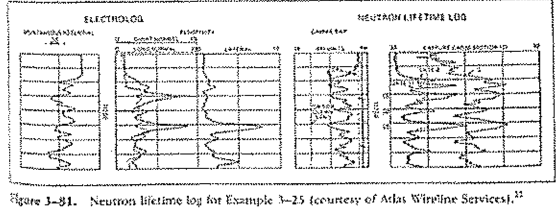


Figure 3–81. Neutron lifetime log for Example 3–25 (courtesy of Atlas Wireline Services).[32]

Similarly for the other two zones:

Depth	Σ_t	GR_{LOG}	I_{GR}	V_{sh}	S_w
11,250–11,253	24	5.9	0.55	0.42	21
11,240–11,249	20	5.2	0.45	0.32	12

CASED HOLE LOGGING

1. PRODUCTION LOGGING
   - PLT
   - PCT (P. Combination Tool)
2. Thermal Decay Time log
   ปล่อย High Energy Neutron
   กระทบกับ Nuclei (Cl_2^-, H_2) แล้ว
   ปล่อย gamma rays
   หา Sw, Porosity
3. CBL / VDL or ~~CBT~~ CET
4. Neutron log

New Tool DPT (Deep Propagation T)

EPT (Electromagnetic Propagation Tool)

BHC (Bottom hole Compensated Sonic)

LSS (Long-Spaced Sonic)

HDT (High-resolution dip meter)

WELLBORE SEISMIC

- WELL SEISMIC TOOL (WST)
- SEISMIC ACQUISITION TOOL (SAT)
- DOWNHOLE SEISMIC ARRAY TOOL (DSA)
- VERTICAL SEISMIC PROFILE (VSP)

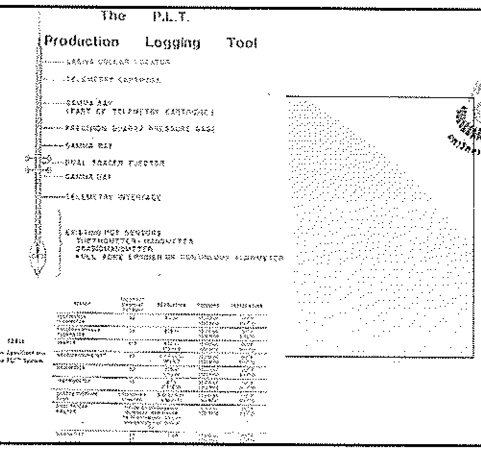
Electromagnetic Propagation logs

EPT

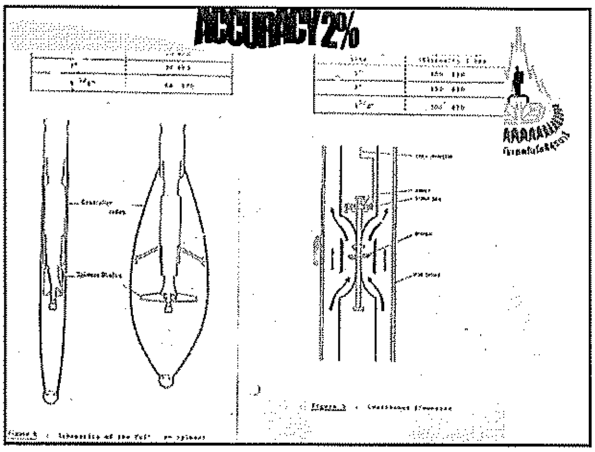
DPT

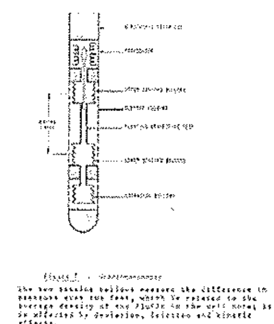
The P.L.T.

Production Logging Tool

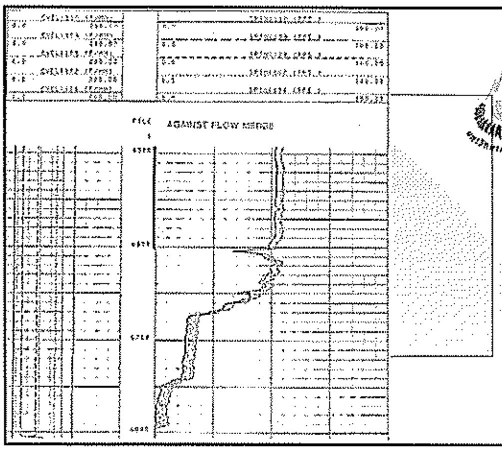


ACCURACY 2%

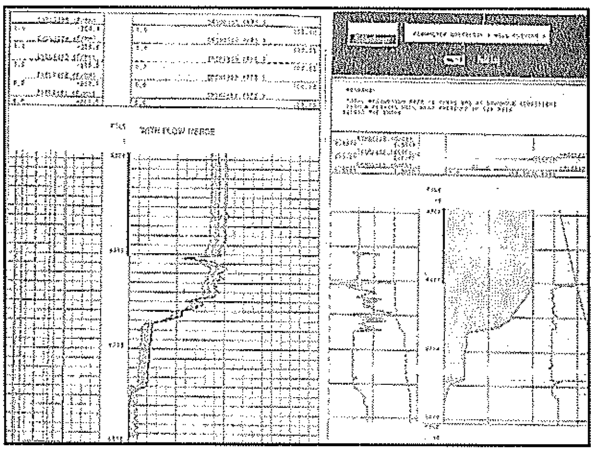


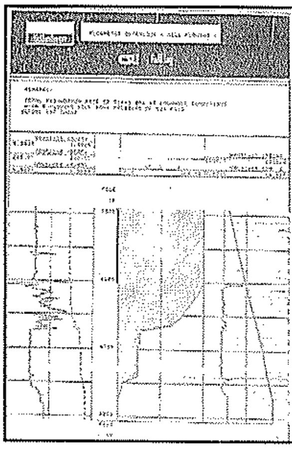


AGAINST FLOW MERGE

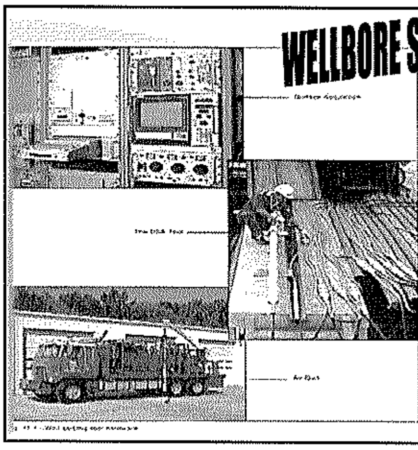


WITH FLOW MERGE





WELLBORE SEISMIC

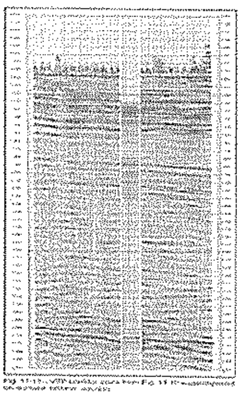


Log and Seismic Tie Effort

- Log Data Validation
  - Check the log quality
  - See if there is any missing log data
  - Determine whether sonic peaks/anomalies representing formation
- Log editing
- Velocity Correction Sonic over VSP (using 4-2 msec resolution)
- Synthetic Seismic Generation
  - Acoustic Impedance
  - Convolution Wavelet to tie seismic and log peaks
    * Extracted Wavelet - to utilize wavelet as seen in the seismic it is highly recommended (similar apperanc
    * Rickr Wavelet - commonly used to have zero phase

Synthetic Seismograms

- Synthetic Seismograms are used to correlate seismic sections
- Theoretically this method uses many simplification and assumptions put into the model
- It provides important link to understand the tie between seismic data and well log responses



VSP& Seismic Section

Velocity Survey

- Velocity or check shot surveys are performed in the wellbore to obtain vertical travel paths through the formations by locating sources and detectors/receivers at certain configuration, normally the receivers are placed near the gelogical horizons
- The survey only utilize first arrival to use in the recorded seismic trace
- First arrivals are then converted into vertical travel times on time-depth graphs which can be used to calculate average velocities
- Sonic log calibration needs to be done prior to generation of synthetic logs, normally borehole effects are found very often causing *drift* which is to be removed to prevent shifting in time of seismic reflections or pesudoevents

Vertical Seismic Profile

- Vertical Seismic Profiling (VSP) uses both entire recorded seismic trace and first break. Receivers are spaced at very closed intervals in the wellbore in order to get a seismic section in the wellbore
- The seismic wave and all effects are measured as a function of depth as it propagates through the formations
- Thr receivers are close to reflectors where up-going and down-going waves are recorded as a function of depth
- The down-going wavelets are used to design deconvolution filters
- In general VSP provide much better spatial and temporal resolution, the signal changes interm of bandwidth and energy loss are measured
- Applicatios of VSP are to correlate the actual seismic events with more confidence, and with much better resolution due to shorter travel paths it can provide a tool to generate high resolution maps, and better estimate of rock properties

Basic Concept of VSP

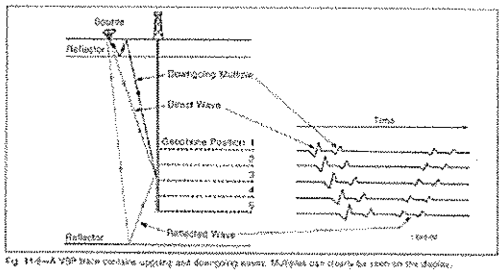


Fig. 11-8—A VSP trace contains upgoing and downgoing waves. Multiples can clearly be seen on the display.

Basic Concept of VSP

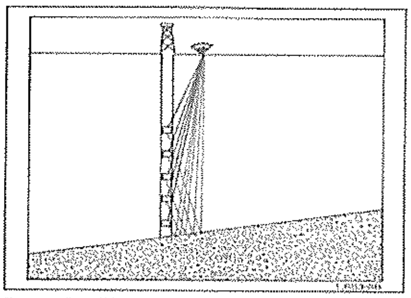


Fig. 11-12—VSP: stationary source, moving receiver.

Offset VSP

Offset VSP are used to detect faults and pincouts
developed to illuminate structure away from the wellbore

Multiple offset and walkaway VSP

Multiple offset VSP were developed to provide high-resolution seismic structural details in the area where interference from the shallow layers
The disadvantages is very time consuming, it requires few days for the acquisition by putting multiple source positioned in different locations

Offset VSP

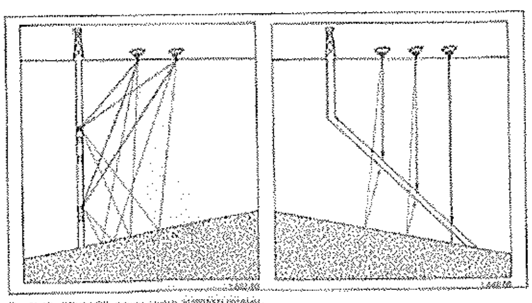


Fig. 11-13—Offset VSP: moving source, stationary receiver.

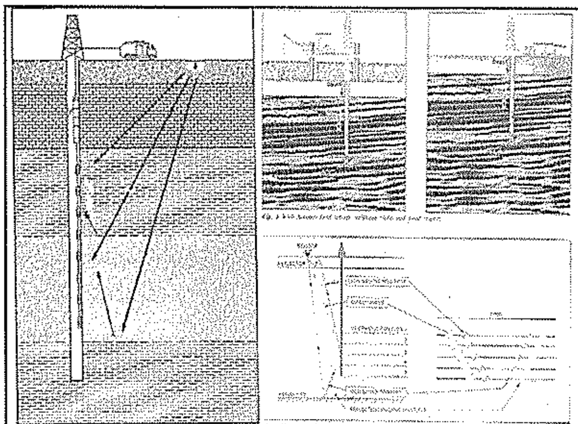


Fig. 11-2—Schematic of DSA tool in operation

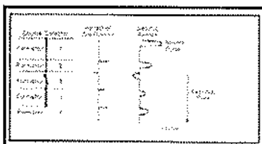


Fig. 11-4—Ideal seismic record giving position (in time) of reflector and value (amplitude) of reflection coefficient.

effect of the invaded zone; this is particularly important in gas-bearing formations. Geogram processing enables qualitative correlations as well as quantitative evaluations of seismic data to be made.

The Geogram processing sequence is shown in Fig. 11-5. The first two steps, which involve editing and sonic adjustments, are normally made during the time-to-depth conversion. Once the reflectivity series and transmission losses have been computed, the decision must be made on what type of wavelet to use for convolution. In order to give the best approximation of the actual source signature, several wavelets are available. These include Ricker minimum- or zero-phase, Klauder, spike with Butterworth filter, or other user-defined operators.

The Geogram display can be made with or without multiples and/or transmission losses, and with any desired frequency or band of frequencies. A typical Geogram display is shown in Fig. 11-6.

The structural dip, as interpreted from a dipmeter survey, can be incorporated into the presentation to permit the Geo

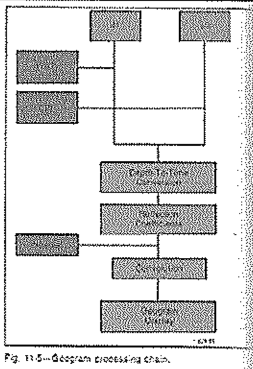
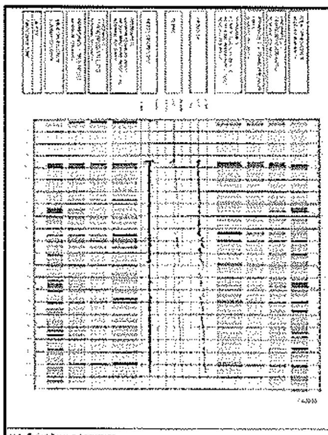


Fig. 11-5—Geogram processing chain.

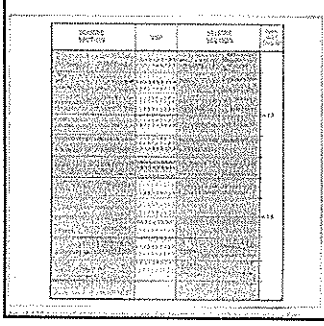
processed data can be presented on a time scale for correlation with the seismic data.

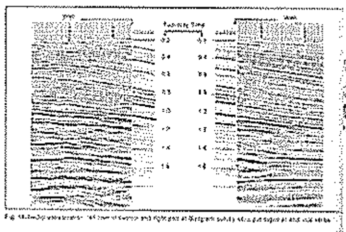
VERTICAL SEISMIC PROFILE

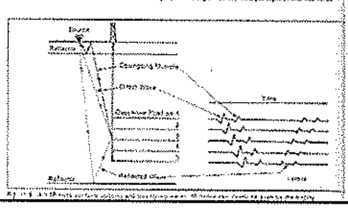


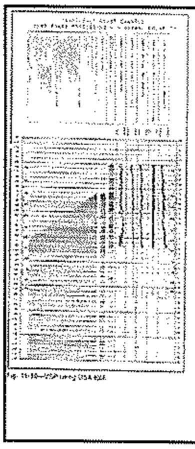
VERTICAL SEISMIC PROFILE

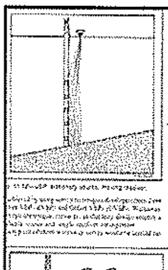
Applications

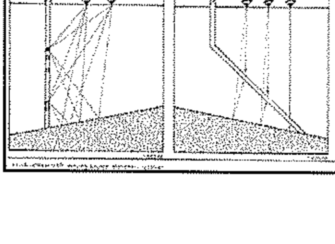


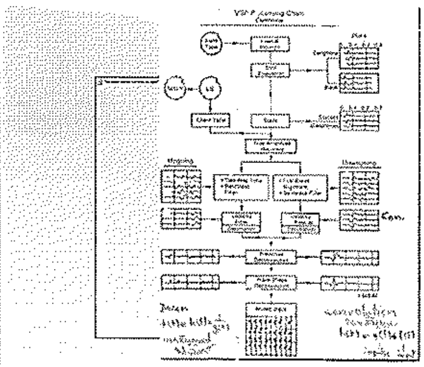




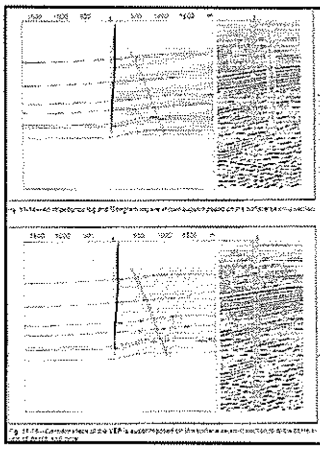


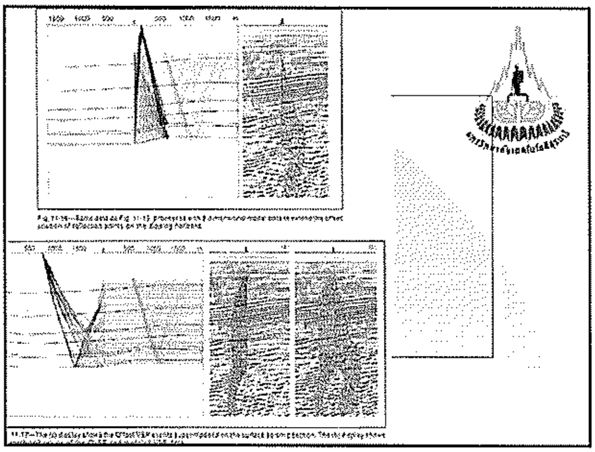


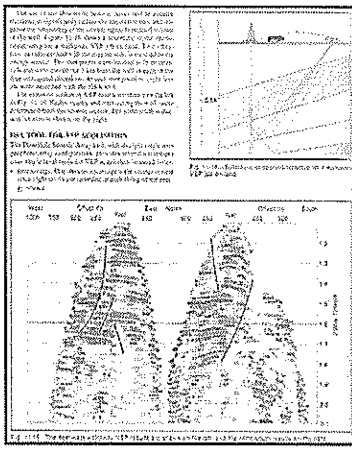


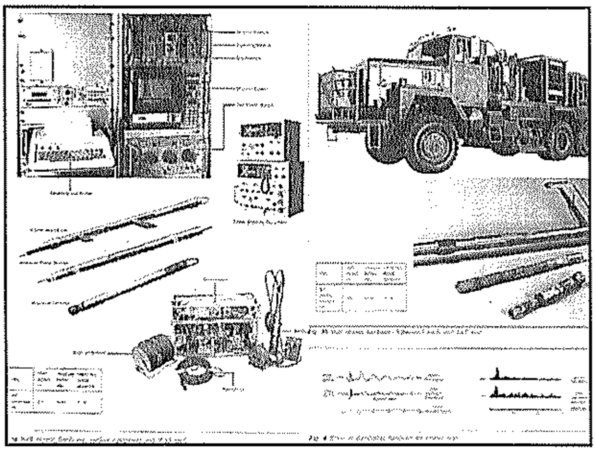


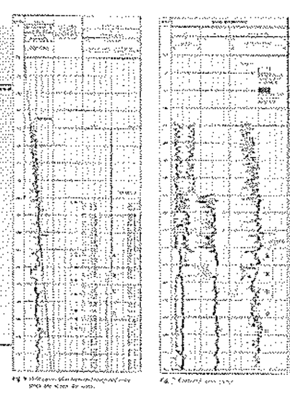
-9—Processing of VSP's involves three major steps:

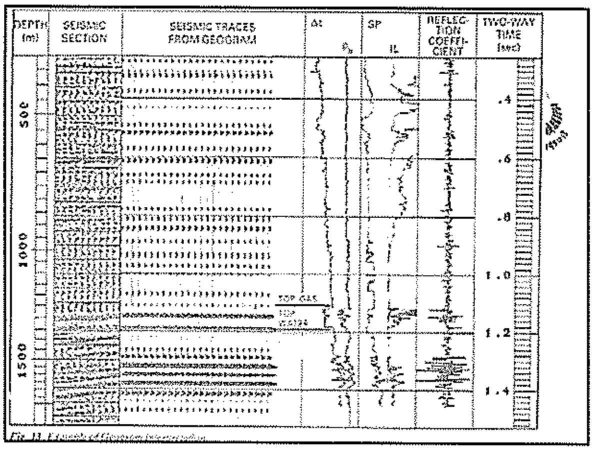


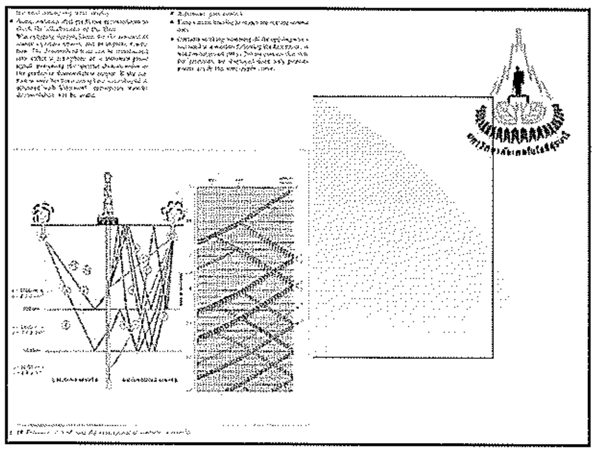


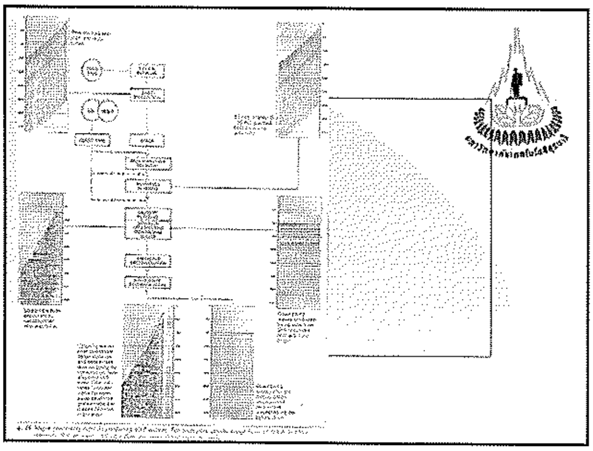


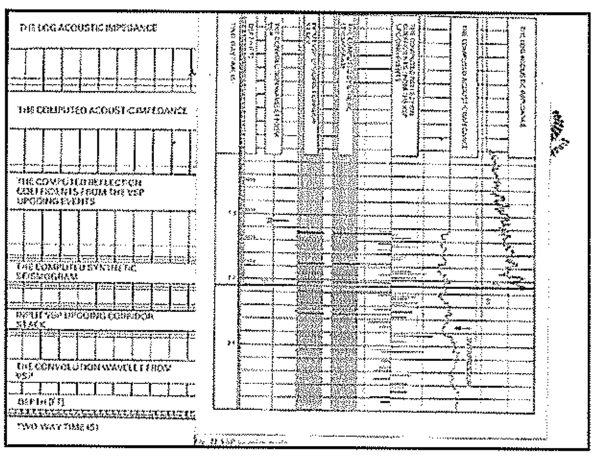


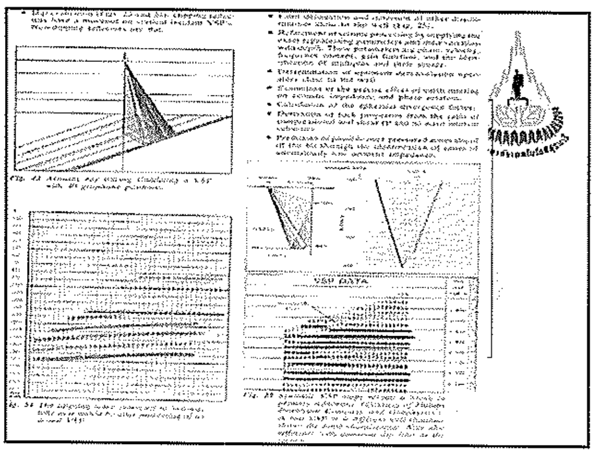


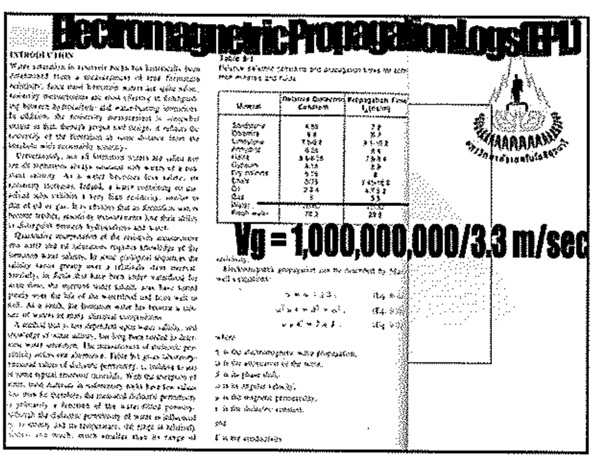

DEPTH (m)
SEISMIC SECTION
SEISMIC TRACES FROM GEOGRAM
SP
REFLECTION COEFFICIENT
TWO-WAY TIME (sec)
500
1000
1500
TOP GAS

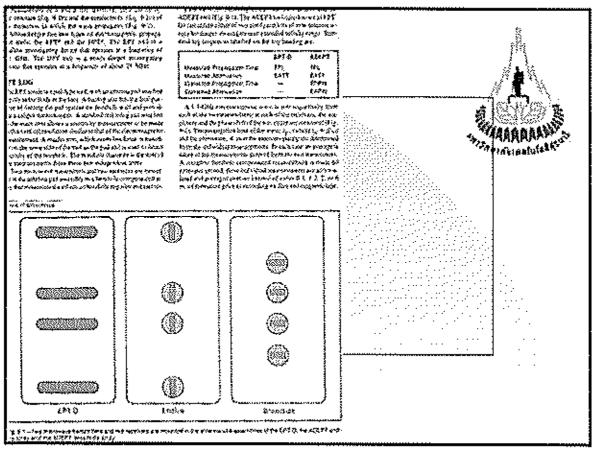


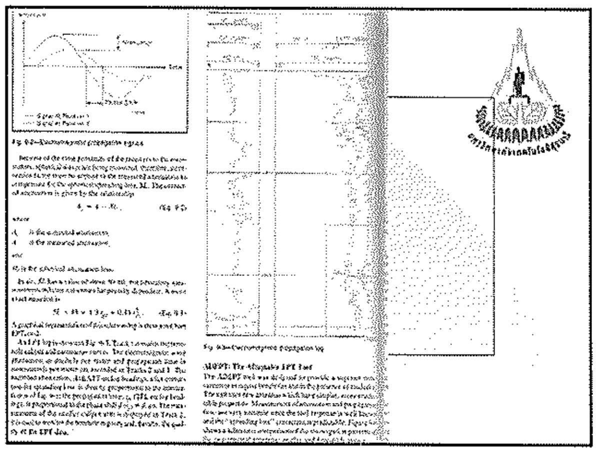


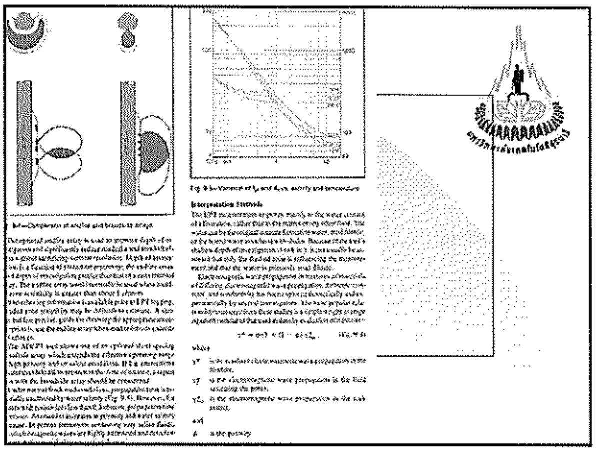

THE COMPUTED ACOUSTIC IMPEDANCE
THE COMPUTED REFLECTION COEFFICIENTS FROM THE VSP UPGOING EVENTS
THE COMPUTED SYNTHETIC SEISMOGRAM
INPUT VSP UPGOING CORRIDOR STACK
THE CONVOLUTION WAVELET FROM VSP
DEPTH (FT)
TWO WAY TIME (S)

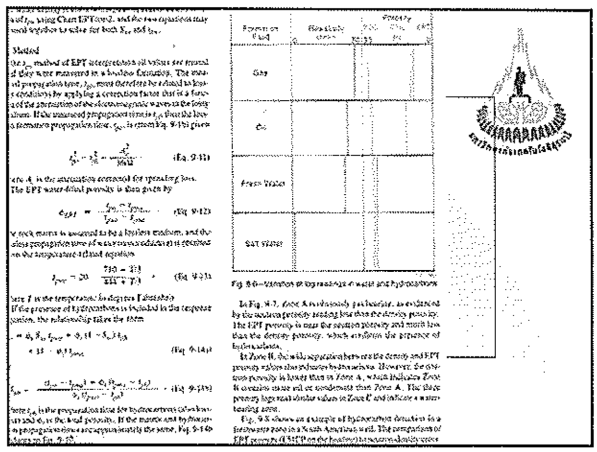

VSP DATA

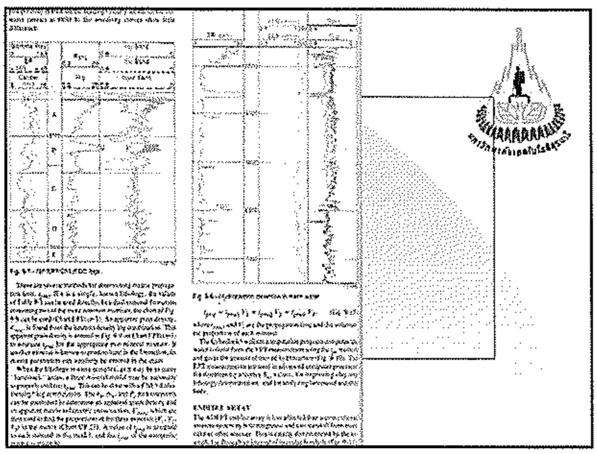

Electromagnetic Propagation Logs (EPL)
INTRODUCTION
Vg = 1,000,000,000/3.3 m/sec

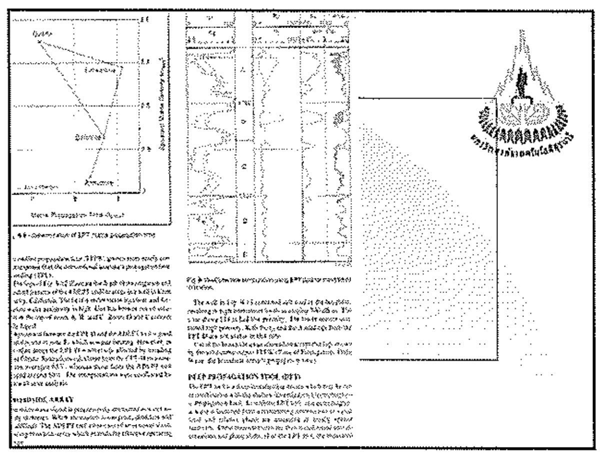


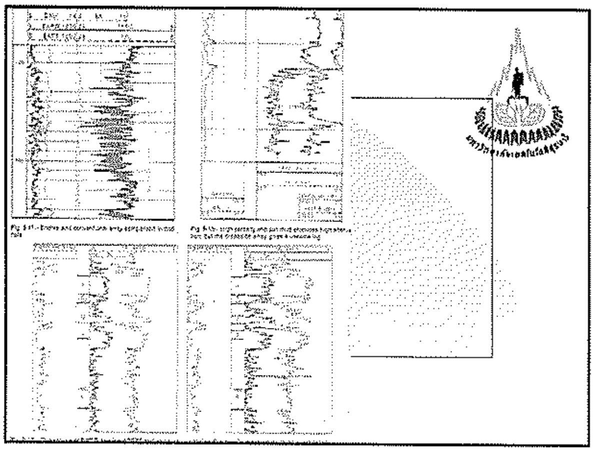


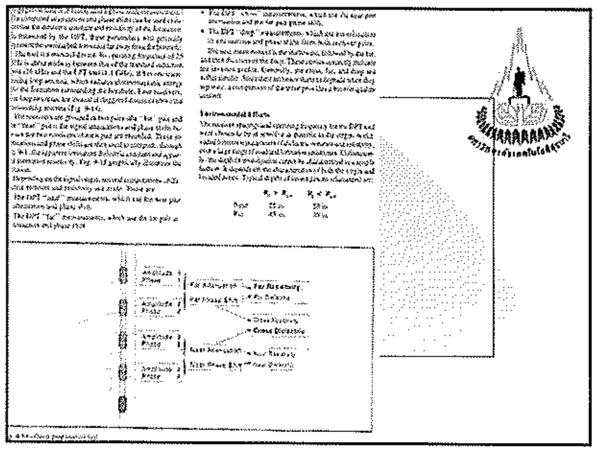




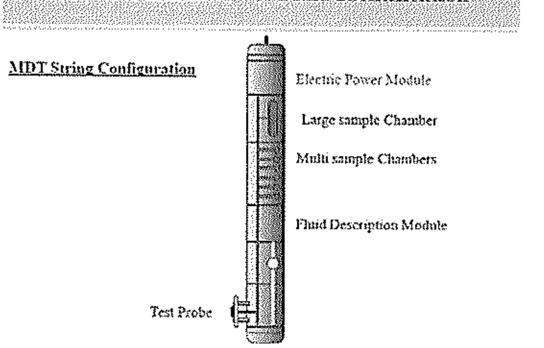




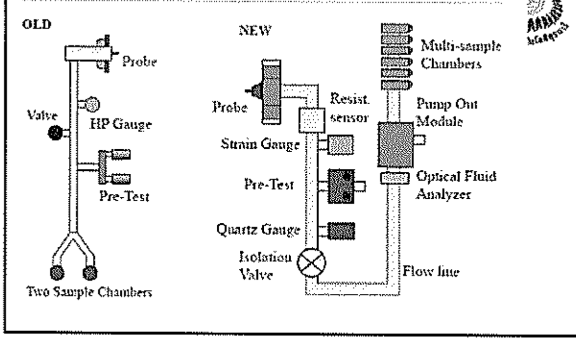




Modern Formation For Fluid Identification

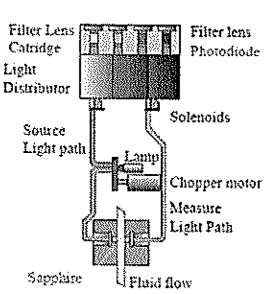


Basic components of the tool



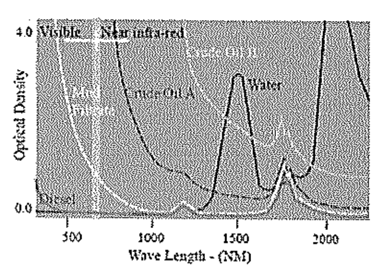
How OFA Divice Operates

OFA Spectrometer

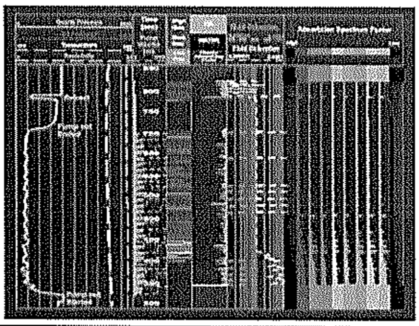


How Can We Differenciate Fluid Types ?

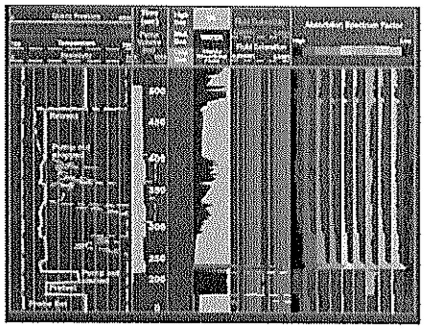
OFA Spectrometer



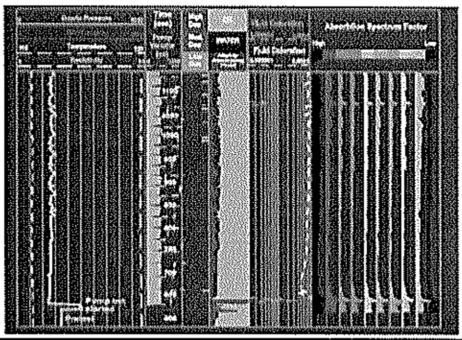
Example-1 : Gas OFA



Example-2 : Water OFA



Example-3 : Oil OFA



FORMATION EVALUATION

1. LOGGINGS

Driller's Logs, Mud Logs

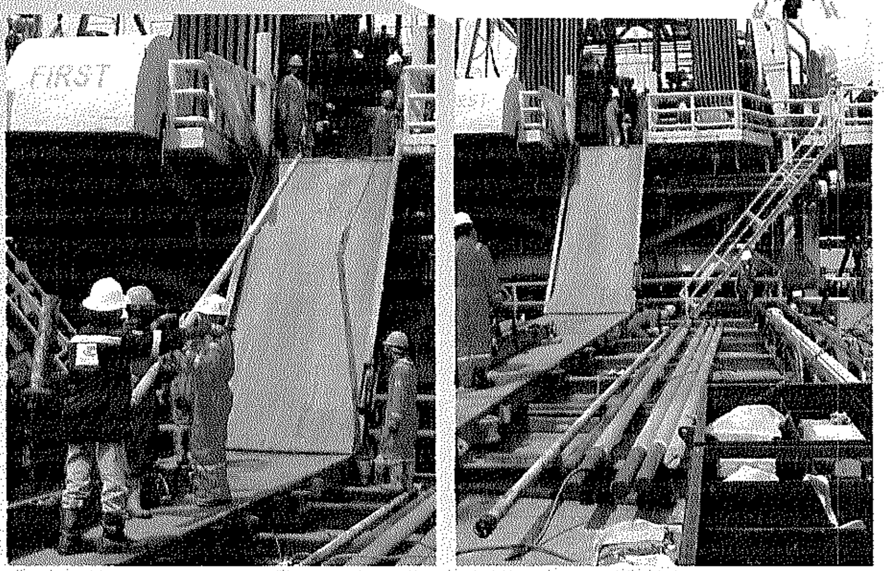
ELECTRIC WIRE LINE LOGS

2. CORE ANALYSIS

3. WELL TESTING

Repeated Formation Tester(RFT)
Drill Stem Test (DST)
Production Test (PT)

Conventional Cores



WELLLOGGING

CHAPTER 20

CORE ANALYSIS

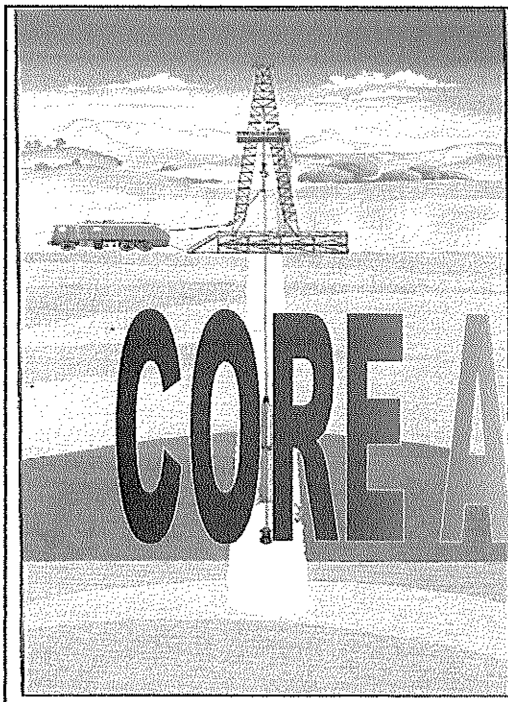


Fig. 1-2—Wireline logging operation

Quantitative Analysis –Part I (2 hrs.)
Density, and Neutron Logs(3 hrs.)
Combined Porosity and Lithology logs Determinations(2 hrs.)
Focused Resistivity Logs (2 hrs.)
QUICKLOOK Interpretations(3 hrs.)
Shaly Sand Interpretations(3hrs.)
Case Hole Logging(3 hrs.)
Computer Processing of well Logs(1 hr.)
Abnormal Pressure(1 hr.)
Fracture Detection with Well Logs(1 hr.)
Dipmeter Principles(2 hrs.)
Logs Correlations(2hrs)
Case Hole Logging(3 hrs.)
Special Logs(1 hrs.)

Core & Core Analysis(2 hrs.)

ROUTINE CORE ANALYSIS

1. POROSITY MEASUREMENT

BULK VOLUME
- LIQUID DISPLACEMENT
- CALIPERING & CALCULATIO

SUMMATION OF FLUID

GAS TRANSFER

-BOYLE'S LAW POROSIMETER

LIQUID RESATURATION

TOLOENE , KOBE POROSIMETER

GRIAN DENSITY

-BOYLE'S LAW

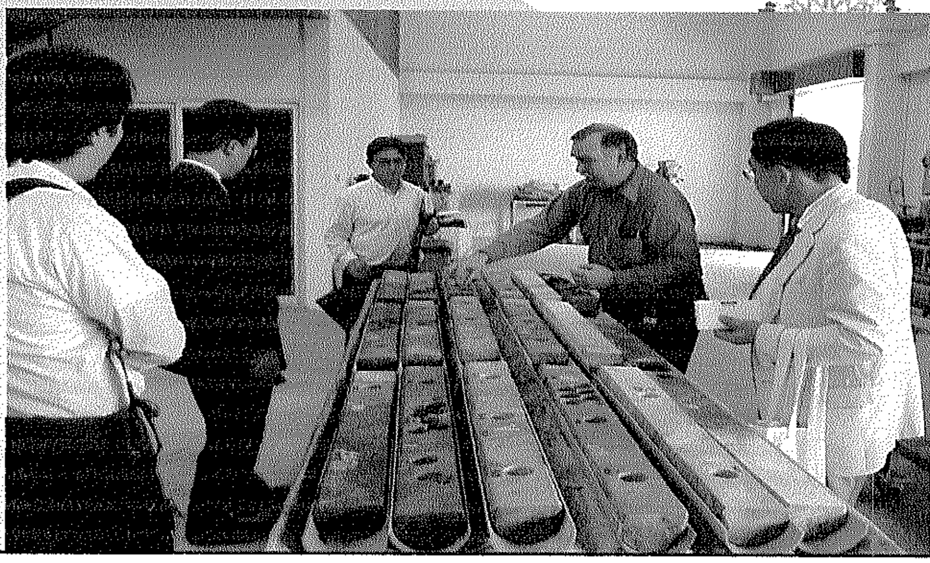
MEASUREMENT φ UNDER CONFINING PRESSURE

HYDROSTATIC LOAD CELL

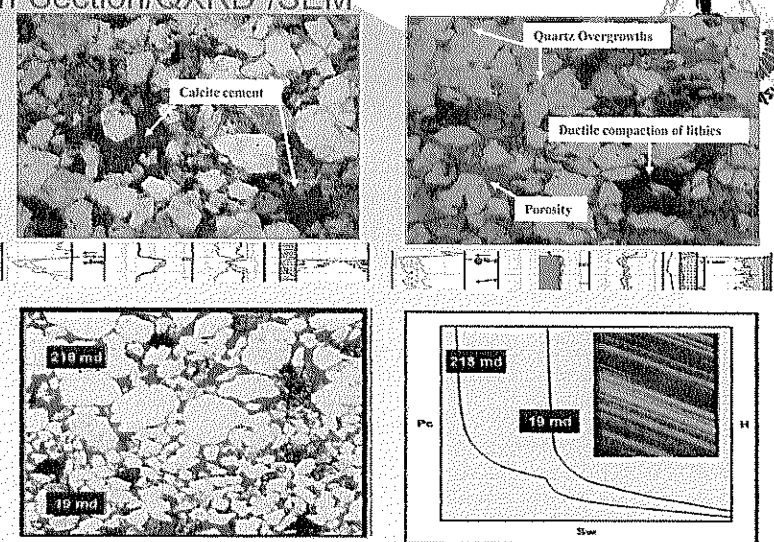
CORE ANALYSIS

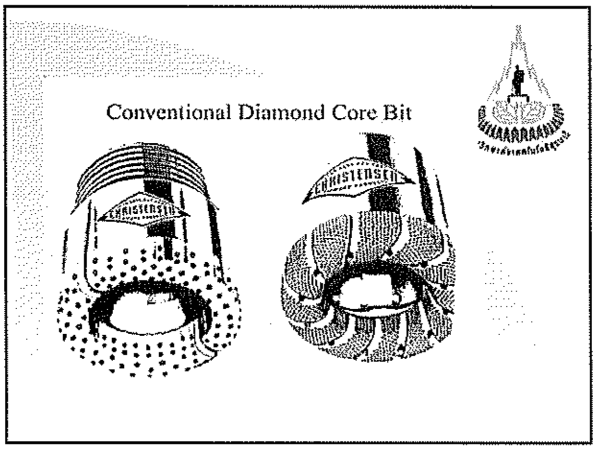
Types of Coring Devices	Core Diameter	Core Length
Conventional Diamond Core	1 3/4-6 inches	30 feet multiples
Percussion Sidewall	1 inch	1 inch
Rubber or Plastic Sleeve	3 inches	20 feet
Pressure Core Barrel	2 5/8 inches*	10 feet

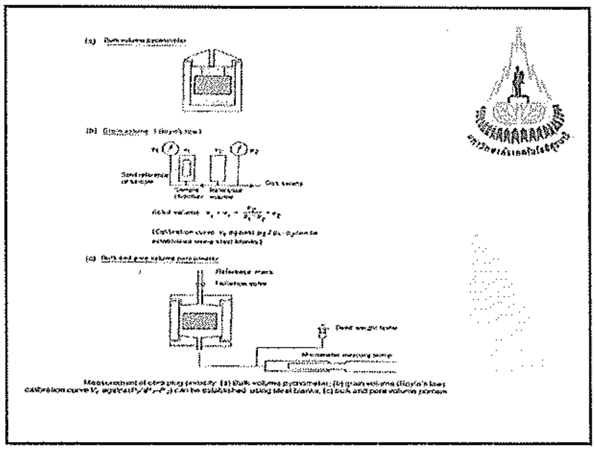
Convention Cores…..
In the Core Laboratory

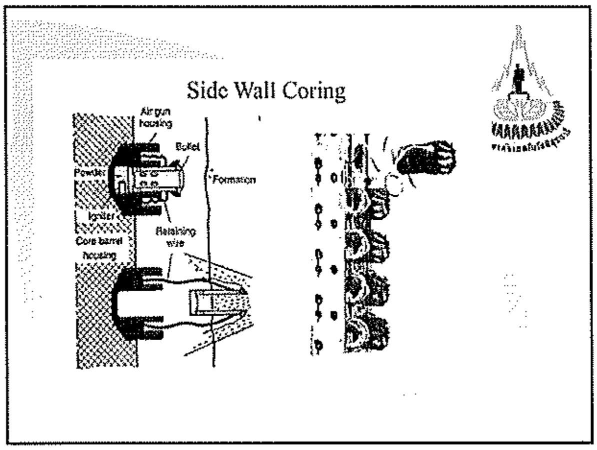


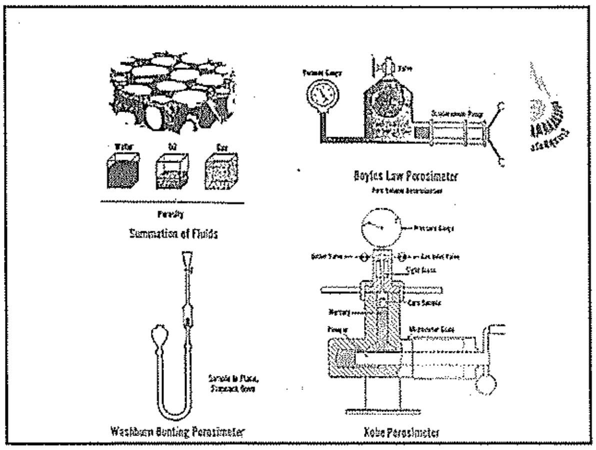
Core Measurements:
Thin Section/QXRD /SEM




Conventional Diamond Core Bit
CHRISTENSEN
CHRISTENSEN




Side Wall Coring
Air gun housing
Bullet
Powder
Formation
Igniter
Retaining wire
Core barrel housing


Water
Oil
Gas
Porosity
Summation of Fluids
Boyles Law Porosimeter
Washburn Bunting Porosimeter
Kobe Porosimeter

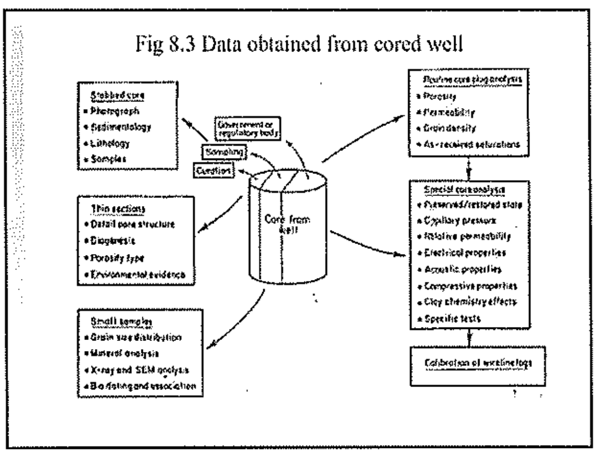
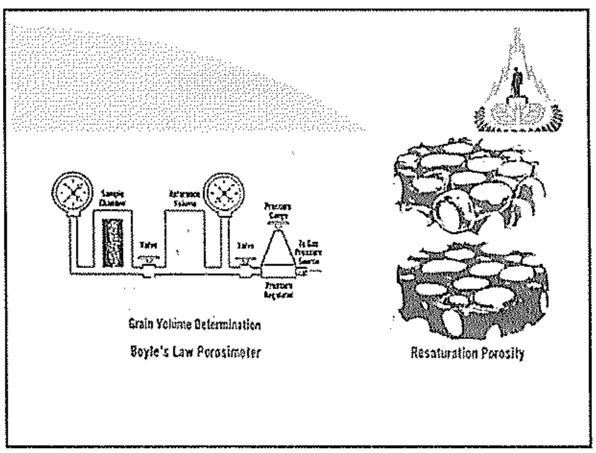


Fig 8.3 Data obtained from cored well
Slabbed core
• Photograph
• Sedimentology
• Lithology
• Samples
Government or regulatory body
Sampling
Curation
Core from well
Routine core plug analysis
• Porosity
• Permeability
• Grain density
• As-received saturations
Special core analysis
• Preserved/restored state
• Capillary pressure
• Relative permeability
• Electrical properties
• Acoustic properties
• Compressive properties
• Clay chemistry effects
• Specific tests
Thin sections
• Detail pore structure
• Diagenesis
• Porosity type
• Environmental evidence
Small samples
• Grain size distribution
• Mineral analysis
• X-ray and SEM analysis
• Bio dating and association
Calibration of wireline logs


Sample Chamber
Reference Volume
Valve
Valve
Pressure Gauge
Pressure Regulator
Grain Volume Determination
Boyle's Law Porosimeter
Resaturation Porosity

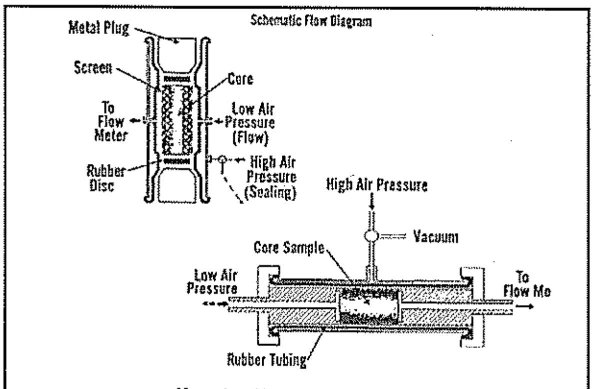
PERMEABILITY Measurement

1. PERMEAMETER (SIDEWALL or CORE PLUG)
2. HASSLER-TYPE

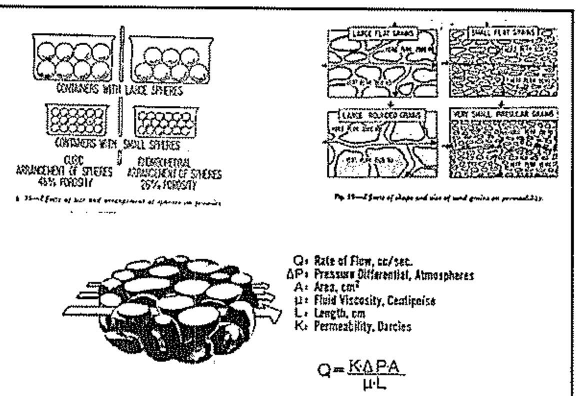
SIDEWALL & CONVENTTIONAL

WHOLE CORE — HORIZONTAL, VERTICAL

3. MEASUREMENT UNDER PRESSURE

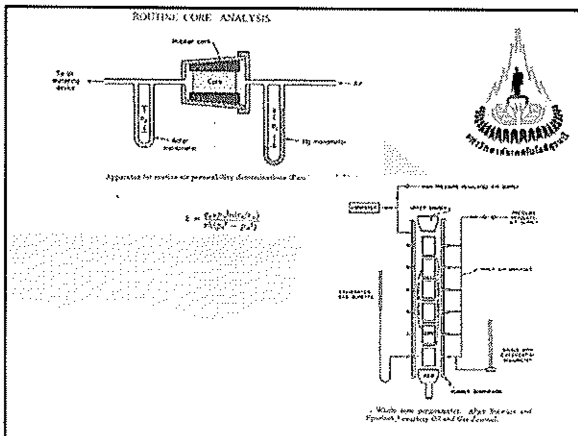


Hassler-Type Core Holders

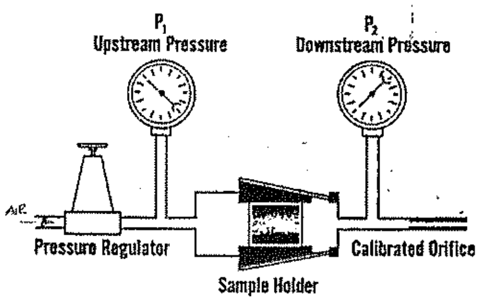


$$Q = \frac{K \Delta P A}{\mu L}$$

Fig 1.20 Permeability



Permeameter



C. SATURATION MEASUREMENT

GAS SATURATION

MERCURY INJECTION 750 PSI

OIL SATURATION

RETORT — DEAN-STASK DISTILLATION

WATER CONTENT

RETORT

Saturation Measurement

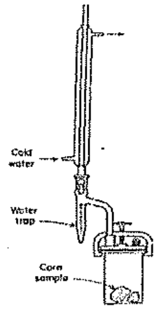


Fig 10.14 Retort apparatus for fluid saturation determination.

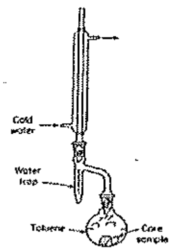


Fig 10.15 Stark-Dean distillation apparatus for water saturation determination

DATA	*Supplementary* USE
1. Vertical Permeability	Define conning probability and gravity drainage potential.
2. Core-Gamma Log	Define lost core and depth relation of core with down-hole logs (requires down-hole gamma-ray)
3. Grain Density	Refine density log calculations.
4. Water Chloride	Define connate water salinity in oil-base cores and degree of flushing in water-base cores.
5. Oil Gravity	Estimate reservoir gravity from correlations based

Interpretations from Core Analysis

1. Prediction of fluid production (gas, condensate, oil or water).
2. Definition of gas-oil, gas-water, oil-water contacts and transition zone.
3. Possibility of gas or water coning.
4. Completion intervals.

SATURATION Measurement

GAS SATURATION
Mercury Injection 750 psi

OIL SATURATION
Retort, DEAN-STASK DISTILLATION

WATER CONTENT
Retort

Special Core Analysis Tests

Static' Tests	*Dynamic Tests*
Pore Volume Compressibility Permeability and Porosity vs Net Overburden • Pressure Petrographic Studies • Mineral Identification (Thin Sections) • Diagenesis • Clay Identification (X-ray) • Grain Size Distribution (Sieve Analysis) • Scanning Electron Microscopy • Cathodoluminescence Wettability Determinations (Room and Reservoir Conditions) Electrical Properties • Formation Factor vs Porosity (at Room and Net Overburden Pressure and Temperature Conditions) • Resistivity Index vs water Saturation • Cation Exchange Capacity Acoustic Velocity (at Net Overburden Pressure) Grain Density Capillary Pressure • Restored State Technique (Air-Brine, Air-Oil, Oil-Water) • Centifugal Technique (Air-Brine, Air-Oil, Oil-Water) • Mercury Injection Technique LowPermeability Gas Sand Evaluation	Liquid Permeability (Evaluation of Completion Workover and Injection Fluid Including Surfactants and Polymers) Relative Permeability • Gas-Oil With Connate water No Connate water • Gas-Water Drainage (Gas Storage Buddle Formation) Inhibition (Water Encroachment Into Gas Zone) • Water-Oil Steady State Non-steady State Residual Gas (after Water Encroachment) Water Flood Evaluations • Fresh and Restored Samples • Room and Reservoir Conditions Enhanced Oil Recovery • Thermal (Steam, In Situ Comp., Hot Water) • Chemical (Caustic, Polymer, Surfactant) • Miscible (CO_2, N_2 Hydrocarbon)

CORE ANALYSIS DATA AND USE

DATA	*Routing Data* Use
1. Porosity	Define storage capacity
2. Permeability (horizontal)	Define flow capacity, permeability distribution and profile.
3. Saturations	Define (1) Presence of hydrocarbons (net pay and contacts) (2) Type of hydrocarbon (gas or oil) (3) Connate water if oil-base mud used
4. Lithology	Define rock type and characteristics of core (fractures, vugular, laminated, etc.)

8.7 APPLICATION OF CORE ANALYSIS

A. EXPLORATION

- Evaluating productive possibilities of edge wells, field extensions,
- wildcats.
- Determining subsurface structural and stratigraphic changes

B. WELL COMPLETION AND WORKOVER OPERATIONS

1. Selection drill stem test intervals
2. Establishing basis for interpretation of drill stem test data in terms of formation characteristics
3. Determining basis for interpretation of drill stem test data in terms of formation characteristics.
4. Selecting completion depths and intervals for plugging, setting packers, cement shutoffs, for water and gas exclusion

Selecting intervals for perforating, shooting, acidizing.
Evaluating effectiveness of completion
Determining intervals for recompletion.

C. FIELD DEVELOPMENT

1. Determining optimum spacing
2. Determining new drilling locations
3. Defining limits of field.
4. Determining capacity of required field equipment.
5. Defining fluid contacts and variations across field.
6. Determining structural and stratigraphic correlations.
7. Establishing basis for interpretation and calibration of other well logging methods
8. Selecting water intake wells and optimum completion intervals.

8.9 CORE PRESERVATION

Commonly Used Preservation Techniques

1. Submerging under deaerated water .
2. Submerging under nonoxidized crude oil or refined oil treated to remove polar compounds.
3. Plastic bags (recommended for short-term storage, 2-3 days only).
4. Saran and aluminum foil coated with wax or strippable plastics.
5. Canning (cans rust and leak with time, and core may dry and deteriorate).
6. Freezing or Chilling with dry ice (core is in CO2 atmosphere as ice sublimes).
7. No preservation except insulation to prevent breakage
8. Rubber sleeve cores may be preserved by capping and tapping sleeve ends.

D. WELL AND RESERVOIR EVALUATION

1. Determining net pay.
2. Estimating initial production, pressure drawdown.
3. Estimating water intake rate, injection pressure.
4. Estimating sequence of depletion, or most likely for water or gas intrusion, where several zones are produced simultaneously.
5. Estimating probable recovery
6. Determining oil or gas in place
7. Providing data for equitable participation in unitized operations.
8. Providing data for comprehensive reservoir studies, and planning for pressure maintenance or secondary recovery operations.
9. Providing subsurface information for the more technical and exacting well-completion and recovery methods of the future.

Boyle's law porosimeters: the operation of these devices is based on the gas law. The two-cell types shown in Figure 8.4 is well known and illustrates the principle involved.

Fig. 8.4 Operation of two cell Boyle's law porosimeter.

$$n_1 + n_2 = n_3 + n_4$$

from which:

where

$n_1, n_2 =$ mols of gas in cells 1 and 2 at condition I

$n_3, n_4 =$ mols of gas in cells 1 and 2 at condition II

From the ideal gas law,

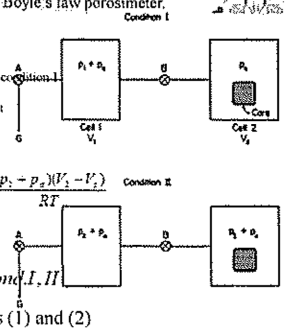
$n = pV/RT$, therefore,

$$\frac{(p_1 - p_a)V_1}{RT} + \frac{p_a(V_2 - V_s)}{RT} = \frac{(p_2 + p_a)V_1}{RT} + \frac{(p_2 + p_a)(V_2 - V_s)}{RT}$$

$$V_s = V_1 + V_2 - \frac{p_1}{p_2} V_1$$

where $p_1, p_2 = gage\ pressure @ cond. I, II$

$V_1, V_2 =$ volumes of cells (1) and (2)



8.8 Calculation Example

Give the following data on a core sample, compute the porosity, and the oil, water, and gas saturations.

1.Sample weight as received from field = 53.50 gm
2.Water volume recovered during extraction = 1.50 cc
3.Sample weight after extracting and drying = 51.05 gm
4.Density of core oil = 0.850 gm/cc
5.Bulk volume of sample = 23.60 cc
6.Grain density of sample = 2.65 gm/cc

Solution:

1) $\varphi = \frac{V_b - V_s}{V_b}$ $\quad V_s = \frac{W_s}{\rho_s}$

$\therefore \varphi = \frac{23.6 - 19.4}{23.6} = 0.178$ or 17.8 %

2) $S_w = \frac{V_W}{V_p} = \frac{1.50}{4.2} = 0.357$ *or* 36 %

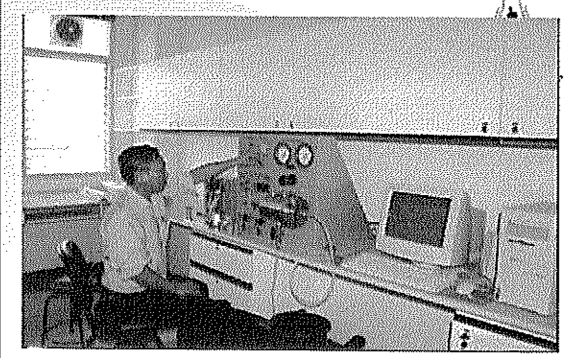
$So = \frac{V_o}{V_p}$ $\quad Vo = \frac{W_o}{\rho_o} = \frac{53.50 - (51.05 + 1.50)}{0.850} = 1.12cc$

$So = \frac{1.12}{4.2} = 0.267$ *or* 27%

Sg = 1-(S_o + S_w) = 1 - (0.27 + 036)

= 0.37 or 37 %

POROSITY & PERMEABILITY MEASUREMENT



$$V_p = \frac{W_s - W_d}{\rho_l}$$

where

$W_s =$ saturated sample weight

$W_d =$ dry sample weight

$\rho_l =$ density of saturating liquid.

Grain volume may also be calculated from:

$$V_s = \frac{W_d}{\rho_s}$$

where

$\rho_s =$ sand grain density.

ρ_s Equation (8.3) is often used with the typical value for of 2.65 gm/cc.

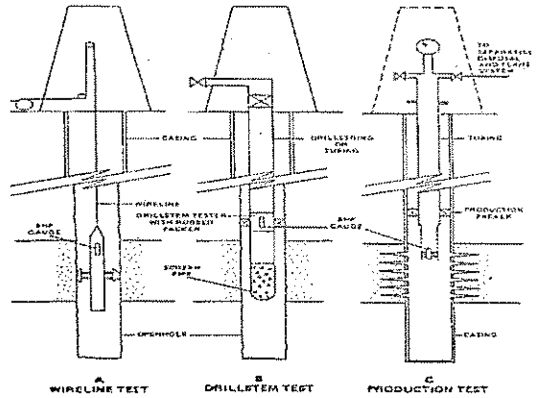


Fig.10.1 Test Techniques

Example 8.11.1

Given the following data, compute the porosity of a cylindrical sample. The grain volume was measured in a two-cell Boyle's law porosimeter.

Sample Dimensions	*Porosimeter data*
Length = 5.00 cm	$V_1 = 25.0cc$
Diameter = 2.50 cm	$V_2 = 45.0cc$
	$p_1 = 100.0psig$
	$p_2 = 50.0psig$

Solution:

$$V_B = \frac{\pi(2.50)^2}{4} \times 4.00 = 19.6\ cc$$

$$V_s = 25 + 45 - \left(\frac{100}{50}\right)25 = 25\ cc \qquad \text{[Eq. (8.1)]}$$

$$\phi = \frac{25.0 - 19.6}{25.0} = 0.216 = 21.6\%$$

Wireline Testing

- CHEAP
- FAST
- RESULTS DEPENDING ON HOLE CONDITION
- LIMITED INFORMATION
- SAFE OPERATION
  - TEST TOOL RUN ON LOGGING CABLE
  - INFO TRANSMITTED TO SURFACE
  - GIVES P.V.T. SAMPLE *
  - MORE THAN ONE INTERVAL
  - TOOLS : FTT (FORMATION TEST TOOL)
    FIT (FORMATION INTERVAL TESTER)
    RFT (REPEAT FORMATION TESTER)
  - LOW SUCCESS RATIO VS COST ACCEPTABLE
  - SAFE – HOLE UNDER CONTROL
    - BOP INSTALLED
    - LUBRICATOR INSTALLED

* H_2S DETECTION CAN BE TOO LOW DUE TO H_2S ENTERING CHAMBER WALL

FORMATION EVALUATION

1. LOGGINGS

Driller's Logs, Mud Logs

ELECTRIC WIRE LINE LOGS

2. CORE ANALYSIS

3. WELL TESTING

Repeated Formation Tester(RFT

Drill Stem Test (DST)

Production Test (PT)

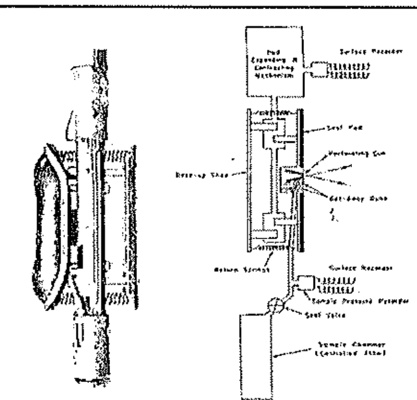


Fig 10.2 Photograph and schematic diagram of wire line formation tester

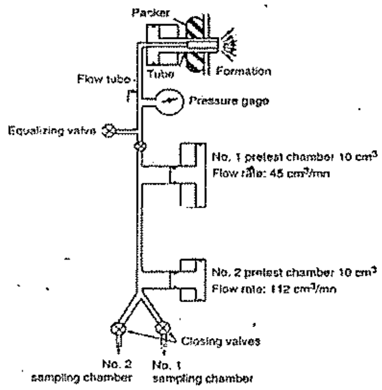


Fig 10.3 Repeated Formation Tester(RFT)

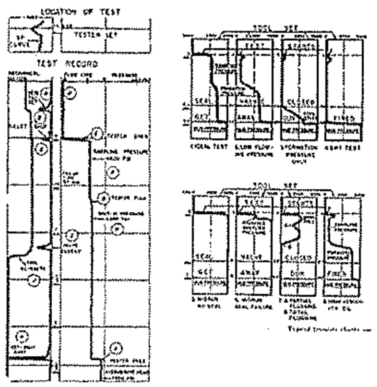
SHORTEN TERM

- **Initial Reservoir Pressure/Temperature**
- **Permeability**
- **Active Pay thickness**
- **Skin Factor**
- **Fluid Type and properties**
- **Type of Flow System**
- **Production Rate/Problems**

LONG TERM

1. **Volume proving**
2. **Extended Investigation Radius**
3. **Reservoir Limits**
4. **Relative Reservoir shape**
5. **Boundary Type**

Fig 10.4 Tester Record and Chart



Drill Stem Test

- RELATIVELY CHEAP AND FAST
- RESULTS MAY BE ADEQUATE
- WELL SAFETY NOT OPTIMUM

PACKER PERFORMANCE IN OPEN HOLE NOT RELIABLE (CASED HOLE FLOATERS)

DRILLSTRING UNSUITABLE FOR HIGH GAS PRESSURE AND H_2S SERVICE

OFFSHORE VESSEL MOVEMENT INDUCES STRING MOVEMENT

- NO DST FROM FLOATERS WITH OPEN HOLE PACKERS
- HARDLY EVER USED IN GROUP OPCO'S

10.4.1 Well Testing Objective

SHORT TERM
- Initial Reservoir Pressure/Temperature
- Permeabilities
- Active Pay Thickness
- Skin Factor
- Fluid Type and Properties
- Type of Flow System
- Production Rate/Problems

LONG TERM
- Volume Proving
- Extended Investigation Radius
  - Reservoir Limits
  - Relative Reservoir Shape
  - Boundary Type

10-49

PRODUCTION TESTING

1. **EXPENSIVE**
2. **SLOW**
3. **EXCELLENT RESULTS AND INFORMATION**
4. **OPTIMUM WELL SAFETY**

(PERMANENT) PACKER IS SET IN CASING

TUBING STRING SELECTED FOR HIGH GAS PRESSURE AND H2S SERVICE

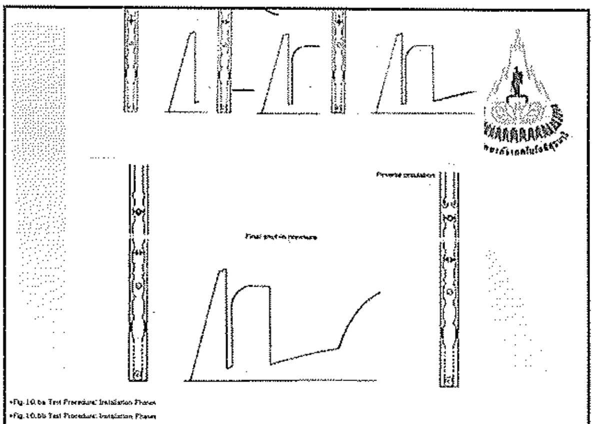
DST Equipment

1. Drill Pipe
2. Packers
3. Tester Valves
4. Pressure Gauges(HP, Amerada, CRG, ec
5. Well head equipment

- well head control valves, and gages.
- Choke manifold
- Separator, heater, and tanks
- Burner, flare, pipes, and others

Considerations

1. Condition Hole
2. Pressure Surges
3. Volume(mud) below the test zone(packer).
4. Types and amount of packers
5. Use of cushions
6. Length of Test (4-72 hours)
7. No. and types of gages(2-3)



•Fig 10.6c Test Procedure: Installation Phases

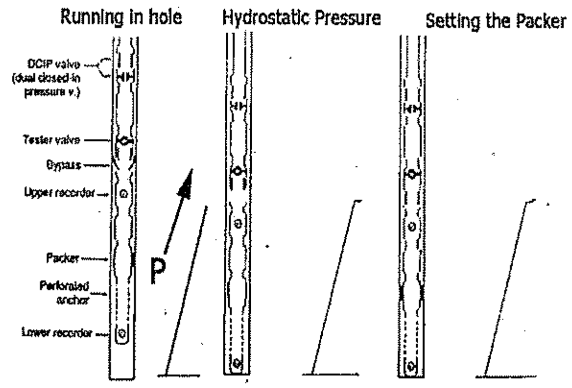


Fig 10.6a Test Procedure: Installation Phases

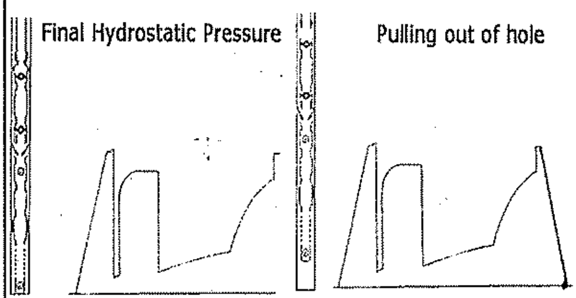


Fig 10.6 Test Procedure: Installation Phases

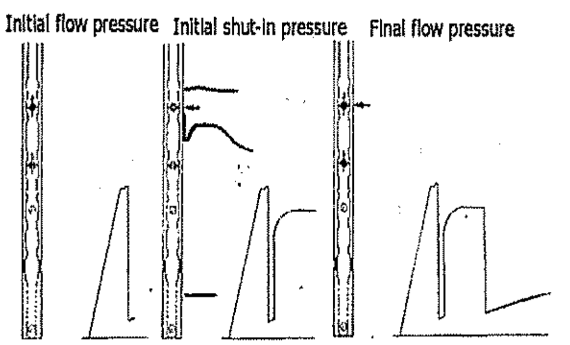


Fig 10.6b Test Procedure: Installation Phases

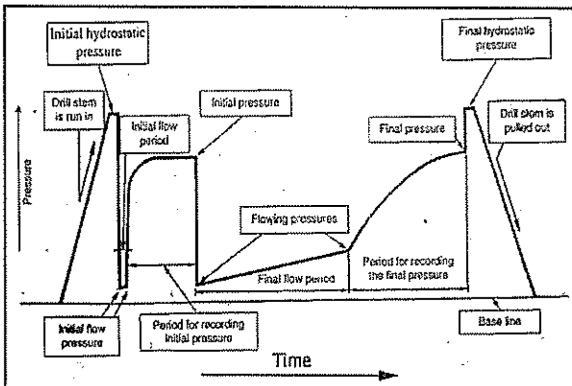


Fig 10.6 Typical Test Diagram

DST Procedure: Installation Phases

When the downhole tools have been run in to the depth of the forma that is going to be tested, the test operation as such can begin as desc below:

- surface connection are made, the test head is installed on the surface,
- the packer is anchored(Fig.10.5a),
- the tester valve is opened: initial flow period, (Fig.10.6b)(10-30 min.),
- the tester valve is closed: pressure build up period (10-30 min.),
- the tester valve is opened: main flow period(2-24 hours),
- the tester valve is closed: pressure build up period (2-48 hours)(10.6c),
- Reverse circulation(Fig. 10.6c),
- the packer is unseated (Fig. 10.6d),
- and pulling out of hole(Fig. 10.6d),

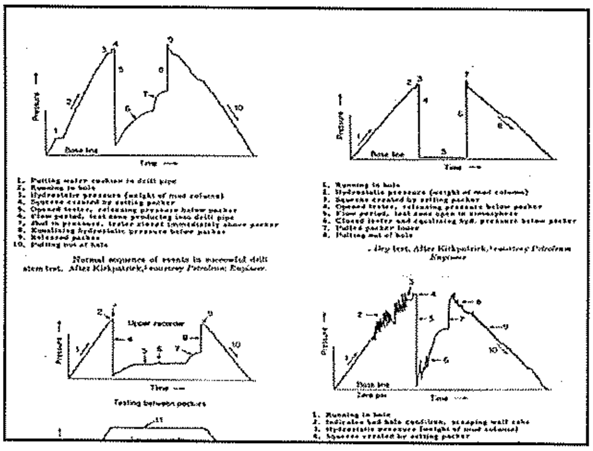
Along with diagrams of test assemblies, we show the variations in pre recorded versus time. The whole recorded diagram is

---

$$p_{ws} = p_e - \frac{0.163 q_o \mu_o B_o}{k_o h} \log \frac{t_o + \Delta t}{\Delta t}$$

$$\overline{m} = -\frac{0.163 q_o \mu_o B_o}{k_o h}$$

$$k_o = -\frac{0.163 q_o \mu_o B_o}{\overline{m} h}$$



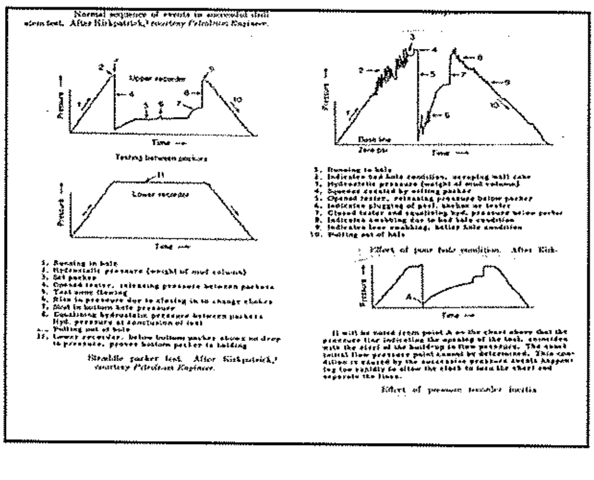
$$\bar{k}_o = \frac{B_o q_o \mu_o \ln(r_e / r_w)}{7.07 h (p_e - p_w)}$$

$$\bar{k}_g = \frac{q_g \mu_g T \ln(r_e / r_w)}{0.704 h (p_e^2 - p_w^2)}$$

$$PR = \frac{\bar{k}_o}{k_o} = \frac{2m \ln(r_e / r_w)}{p_e - p_w}$$

- where PR = productivity ratio

$m = \Delta p_c / \ln 10 = \Delta p_c / 2.3$



Δp_c = pressure drop per common (base 10) logarithm ccycle from the build up curve

- For drill stem test purposes, it is often assumed that $\ln(r_e/r_w) \cong 3$ (r_e/r_w = 500), then:
- (10.21)

$$PR \cong 5.5 \frac{\Delta p_c}{p_e - p_w}$$

- or Damage Factor(DF) is:
- (10.22)

$$DF = \frac{1}{PR} = 0.183 \frac{p_e - p_w}{\Delta p_c}$$

(10.26)

$$S = 1.151\left[\frac{P_{1hr} - P_{wf}}{m} - \log_{10}\frac{k}{\phi\mu\bar{c}r_w^{\,2}} + 3.23\right]$$

where P, P_{wf} = psi, m = slope psi per $\log_{10}$ cycle, k = md, ϕ = fraction, μ = cp,

$\bar{c}$ = $(psi)^{-1}$ and r_w = ft

It is possible, but not generally very useful, to interpret the skin factor as a zone of radius r_s within which the permeability is altered to some value k_s ... when

(10.26)

$$S = \left\{\frac{k}{k_s} - 1\right\}\log_e \frac{r_s}{r_w}$$

The ratio of theoretical pressure drop to the actual pressure drop may be considered an index of the flow efficiency (E).

(10.27)

$$\text{Efficiency} = \frac{P^* - P_{wf} - \Delta P_{skin}}{P^* - P_{wf}}$$

If longer test time data was recorded, the radius of investigation can be obtained from:

(10.27)

$$r_{inv} = \sqrt{\frac{0.000264kt}{0.25\phi\mu c}} = \sqrt{0.00105\frac{kt}{\phi\mu c}}\text{, ft}$$

where t (in hrs.) is the time of flowing for flowing test or the time of shut-in for buildup test.

10.8 Calculation Example

The data in Table were obtained in a pressure buildup test on an oil well in Indonesia. The well was produced for an effective time of 15 hours at the final rate. Other data include.

q_o = 5,535 STD/D	μ_o = 0.89 cp	B_o = 1.31 RB/STB
$c_o \approx 9.5\times10^{-6}$ 1/psi	h = 110 ft	d = 8.681 in.
$c_w = 3\times10^{-6}$ 1/psi	r_w = 0.362 ft	$k_H = k_v$
$c_f = 1\times10^{-6}$ 1/psi	S_w = 38%	ϕ = 23%
Bit dia. = 12.25 in.	Casing ID = 8.681 in.	

Determine:

(a) Total isothermal compressibility
(b) Permeability k
(c) Skin factor s
(d) Pressure drop due to skin $(\Delta p)_{skin}$
(e) Effective wellbore radius r_{we}
(f) Flow efficiency, FE using p^*
(g) Damage ratio, DR using p^*
(h) Productivity index, PI
(i) Radius of investigation at Δt = 5 hours
(j) It is initially assumed that the well is draining from the center of a circle. Is it valid to equate $\bar{p}$ to p^*?

Pressure Drawdown Equation

$$p(r,t) = p_i - \frac{162.6q\mu B}{kh}\left[\log\frac{kt}{\phi\mu c_t r^2} - 3.23\right]$$

$$p_{wf} = b + m\log(t)$$

where,

p_{wf} = flowing well pressure in psia

b = constant

t = time in hrs

$m = \text{constant} = -\dfrac{162.6q\mu B}{kh}$ $\qquad k = -\dfrac{162.6q\mu B}{mh}$

$$S = 1.151\left[\frac{p_{1hr} - p_i}{m} - \log\frac{k}{\phi\mu c_t r_w^2} + 3.23\right]$$

Solution: To solve this example, refer to the Horner Plot in Fig. 10.10

Table oil well pressure buildup test data for example

Δt (min)	$\dfrac{t_p + \Delta t}{\Delta t}$	p_{ws} (psia)	$\Delta p = p_{ws} - p_{wf}$ (psia)
0	0	2,710 = p_{wf}	0
1	901.0	2,760	50
2	451.0	2,803	93
4	226.0	2,823	113
5	181.0	2,825	115
7	129.6	2,828	118
9	101.0	2,830	120
12	76.0	2,831	121
20	46.0	2,832	122
60	16.0	2,837	127
120	8.5	2,839	129
300	4.0	2,842	132
420	3.1	2,842	132
550	2.6	2,842	132

Pressure Build Up Equation

$$p_{ws} = p_i - \frac{162.6q\mu B}{kh}\left[\log\frac{(t_p + \Delta t)}{\Delta t}\right]$$

$$m = -\frac{162.6q\mu B}{kh}$$

$$k = -\frac{162.6q\mu B}{mh}$$

$$S = 1.151\left[\frac{p_{wf}(\Delta t = 0) - p_{ws}}{m} - \log\frac{kt_p\Delta t}{\phi\mu c_t r_w^2(t_p + \Delta t)} + 3.23\right]$$

(a) $c_t = c_o S_o + c_w S_w + c_f$

$= (9.5\times10^{-6})(1 - 0.38) + (3.0\times10^{-6})(0.38) + 10^{-6}$

$= 8.05\times10^{-6}$ 1/psi

(b) $k = 162.6\dfrac{q_o\mu_o B_o}{mh} = 162.6\dfrac{(5{,}535)(0.89)(1.31)}{(8.7)(110)}$

$= 1{,}096.45$ md

(c) $S = 1.151\left[\dfrac{P_{1hr} - P_{wf}}{m} - \log_{10}\dfrac{k}{\phi\mu c r_w^{\,2}} + 3.23\right]$

$= 1.151\left[\dfrac{2{,}837 - 2{,}710}{8.7} - \log\left[\dfrac{1{,}096.45}{(0.23)(0.89)(8.03\times10^{-6})(0.362)^2}\right] + 3.23\right]$

$= 1.151(14.6 - 9.71 + 3.23)$

$= 9.35$

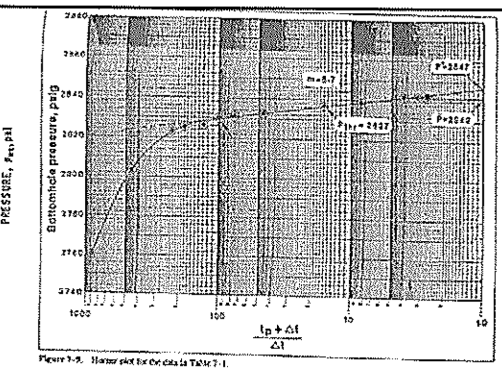


Figure 7-9. Horner plot for the data in Table 7-1.

Fig 10.10 Shut-in bottom hole pressure (p_{ws}) vs Log ($\frac{t_p+\Delta t}{\Delta t}$)

4. Next, the pressure build-up section is divided into conven... increments and the pressures at successive intervals are tab... These are shown as p_1, p_2, etc., on Fig 10.11. Note that the pr... time t was 80 min.

Pressure, atm	Δt min	(t + Δt)/Δt
p_1 = 3460	10	9
p_2 = 3900	20	5
p_3 = 4190	30	3.67
p_4 = 4300	40	3
p_5 =4375	50	2.60
p_6 =4400	60	2.33
p_7 =4410	70	2.14

The build-up curve is plotted as Fig. 10.12. Note that only the l... points fall on the extrapolation to p_e = ICIP = 4500 psig. This illustrates the advantage of obtained an ICIP for extrapolation purposes.

(a) The productivity ratio may be calculated from Eq. (13.6)

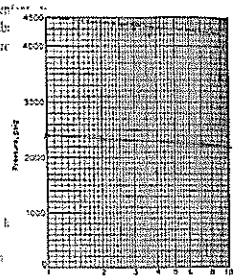
Δp_c = 4500 – 4200 = 300 psi per cycle = m

p_e = 4500

p_w = FFP = 2700 psig

and

$$PR = 5.5\left(\frac{300}{1800}\right) = 0.92$$



(d) $(\Delta P)_{skin} = 0.869ms$

$= (0.869)(8.7)(0.35)$

$= (70.77)$ psi

(e) $r_{wa} = r_w e^{-s}$

$= 0.362e^{-0.35} = 3.15 \times 10^{-4}$

(f) $\text{Efficiency} = \frac{P^* - P_{wf} - \Delta P_{skin}}{P^* - P_{wf}} = \frac{2,847 - 2,710 - 70.77}{2,847 - 2,710} \times 100$

$= 48.34\ \%$

(g) DR = 1/Efficiency

$= 1/0.4834 = 2.07$

(h) $PI = \frac{q_o}{P^* - P_{wf} - (\Delta p)_{skin}} = \frac{5,535}{2,847 - 2,710 - 70.77} = 83.57$ STB/D/psi

the radius of investigation is estimated

(i) $r_i = \left(\frac{k\Delta t}{948\phi\mu_o c_t}\right)^{0.5} = \left[\frac{(1,096.45)(5.0)}{(948)(0.25)(0.89)(8.03 \times 10^{-6})}\right]^{0.5} = 1,875.68$ ft

(b) The estimated productivity index is:

$$J_o = \frac{1980}{4500 - 2700}$$

= 1.1 bbl tank oil/day/psi at a PR = 0.92

or,

$$J_o = \frac{1.1}{0.92} = 1.2 \text{ at a PR} = 1$$

Note that the formation volume factor B_o is omitted. Actually, the oil recovered in the drill pipe is neither tank oil nor reservoir oil, but something in between. If *PVT* or other data are available so that B_o may be estimated, the calculations may be refined. The seriousness of this omission is, however, minor as far as DST estimates are concerned.

(c) calculation of unaltered reservoir permeability required a knowledge of fluid viscosity. Since it is unusual to have such data at the time of a DST, Black has presented the correlation, which may be used for oil viscosity estimates.

Example 10.2

The pressure chart for a DST is given in Fig. 10.11. Other available data are listed below

Interval tested = [illegible]

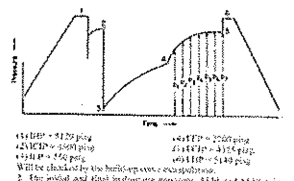
Mud density = 9.8 lb/gal

Recovery = [illegible] ft mud, 7200 ft clean 40°API oil, no water

No water blanket run

Drill pipe = 4 ½ in., [illegible]   I.d. = 3.826 in.

1. The sequence of events is clear from the chart. Note that the pressure apparently stabilized during the initial closed-in period, hence the static reservoir pressure is probably very closely approximated by 4500 psig, the ICIP, etc.



(1) IHP = 5129 psig (4) FFP = 2700 psig

(2) ICIP = 4500 psig (5) FCIP = 4325 psig

(3) IFP = 350 psig (6) FHP = 5140 psig

Will be checked by the build-up curve extrapolation.

2. The initial and final hydrostatic pressures, 5129 and 5140 psig, may be compared with the value calculated from the mud density

$p_h = \frac{9.8}{8.33}$ [illegible]

This is excellent agreement.

3. The oil recovery during the 80-min flow test was

[illegible]

The corresponding average daily oil producing rate is

$q_o =$ [illegible]

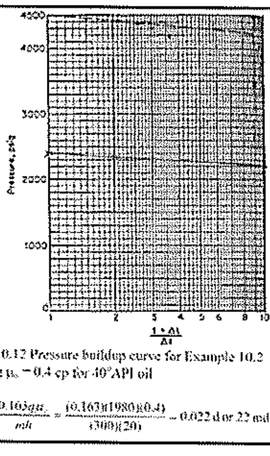


Fig. 10.12 Pressure buildup curve for Example 10.2

Using μ_o = 0.4 cp for 40°API oil

$$k_o = \frac{0.163q\mu_o}{mh} = \frac{(0.163)(1980)(0.4)}{(300)(20)} = 0.022 \text{ d or } 22 \text{ md}$$