SLBS ENGINEERING COLLEGE

DEPARTMENT OF PETROLEUM ENGINEERING

LABORATORY MANUAL

SEISMIC PROSPECTING & FORMATION EVALUATION

CONTENT

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EXPERIMENT NO – 1

Study of SP and Gamma Ray logs to identify bed boundaries

SPONTANEOUS POTENTIAL LOG

PRINCIPLE

SP arises due to salinity contrast between formation water and mud filtrate against permeable beds. No current is sent into the formation. The SP log is recorded by measuring the potential difference in milli-volts between an electrode in the borehole and a grounded electrode at the surface. The change in voltage through the well bore is caused by a build up of charge on the well bore walls. Shales and clays will generate one charge and permeable formations such as sandstone will generate an opposite one. This build up of charge in turn caused by differences in salt content and formation water.
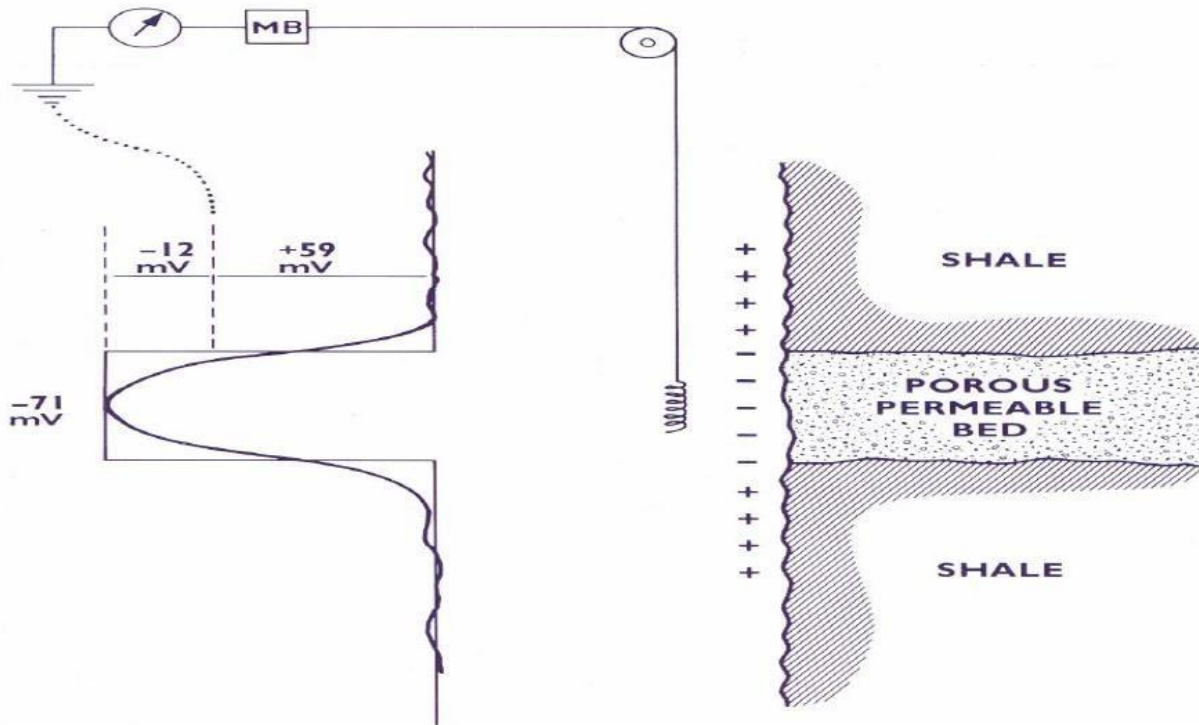
A Schematic for measurement of SP

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

GAMMA RAY LOG

The standard gamma ray tool contains no source and it responds only to gamma ray emission from

the downhole environment. Potassium (K40), Uranium (U238), Thorium (232) is the main radioactive materials. The main types of detectors are Geiger Muller detector or Scintillation Counters with NaI, CsI or BGO crystals (Photomultiplier, to measure incident gamma radiation). The detector is unshielded and will thus accept radiation from any direction.

APPLICATION
- ✓ The gamma ray is particularly useful for defining shale beds when sp curve is rounded.
- ✓ It is used as a quantitative indicator of shale content.
- ✓ Detection and evaluation of radioactive minerals.
- ✓ Delineation of non-radioactive minerals including coal beds.
- ✓ Correlation in cased hole operations.
- ✓ The gamma ray log used in connection with radioactive tracer operation.

GR - VSH Quick Look Evaluation
- ✓ Gamma Ray (GR) Evaluation Technique (Natural occurring radioactive elements in nature: K40-Potassium, Th232-Thorium, U238-Uranium
- ✓ Spectral GR tool can discriminate between these elements, standard GR tool only provides the total GR counts
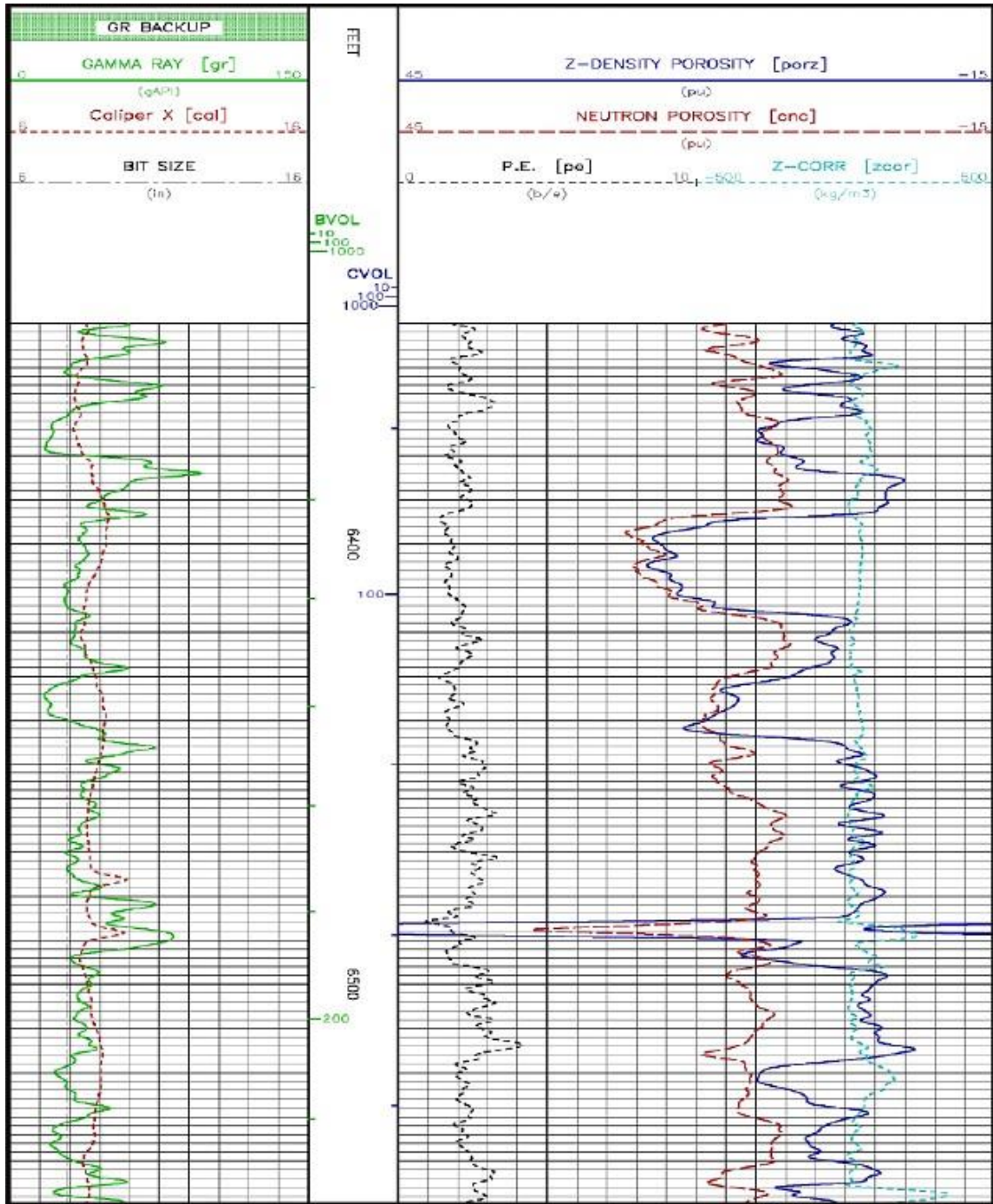
Reservoir rocks with low GR (Sandstone/Limestone/Dolomite). Shale has large amount of Th and K atoms and that's why high GR.

$$V_{sh} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$$

V_{sh} : Shale volume
GR : GR Log reading
GR_{max} : GR Log reading in Shale zone
GR_{min} : GR Log reading in clean Sand zone
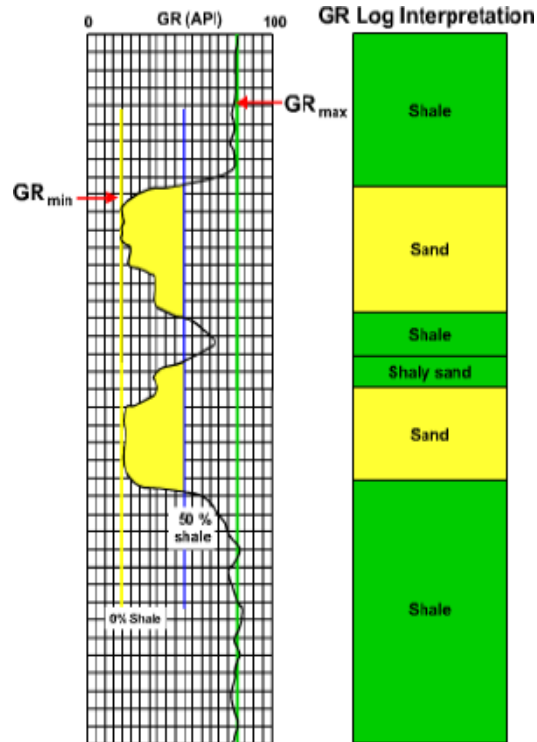
DENSITY, γ –RAY AND NEUTRON LOG

Identification of fluid types in pore spaces by resistivity logs

RESISTIVITY LOGGING

The resistivity of a substance is its ability to impede the flow of electric current through the substance. Formation resistivity usually falls in the range from 0.2 to 1000 ohm meter. Resistivity higher than 1000 ohm-m is uncommon in permeable formations. In a formation containing oil or gas, both of which are electrical insulators resistivity is a function of formation factor, brine resistivity and water saturation which in term depends on true resistivity. Of the formation parameters resistivity is of particular importance because it is essential for saturation determination mainly of the hydrocarbon. Depending upon the environment under which resistivity logs are recorded. There are two types of resistivity Logs. They are Latero logs and Induction logs.

DUAL LATERAL LOG

The dual lateral log has been one of primary resistivity measurement device. DLL is a focused electrode device designed to minimize influence from borehole fluids and adjacent formations. The DLL consists of an electronics section and a mandrel section. The mandrel supports the electrodes which are connected to the electronic circuitry. The measurement current emitted from center electrode is forced to flow laterally into the formation by the focusing action of electrodes surrounding the center electrode. It provides two measurements of the subsurface resistivity simultaneously. The two measurements have differing depth of investigation are called

deep resistivity (R_d) and shallow resistivity (R_s).

THEORY

DLL consist of a current emitting center electrode positioned between guard electrodes. A known current is passed through the current electrode with a return electrode at the surface. Simultaneously a potential is applied to the focused electrode to keep zero potential difference between guard and center electrode thereby the current is focused into the formation. Thus the potential difference produced is equivalent to the formation resistivity. The lateral log current path is basically a series circuit consisting of the drilling fluid, Mud cake, flushed zone, invaded zone and the virgin zone, with the largest voltage drop occurring over the highest resistance zone.
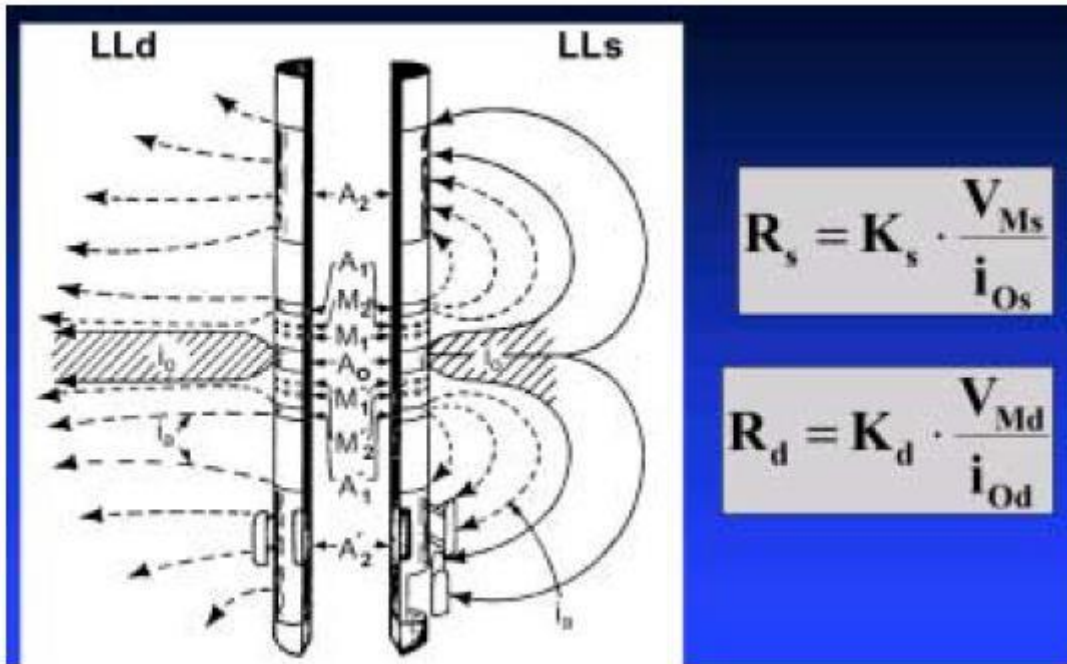
The total amount of current emanating from an electrode must flow through any Medium that encompasses the electrode. The depth of investigation of a lateral log is defined as the depth at which 50% of the total measured voltage is dropped.
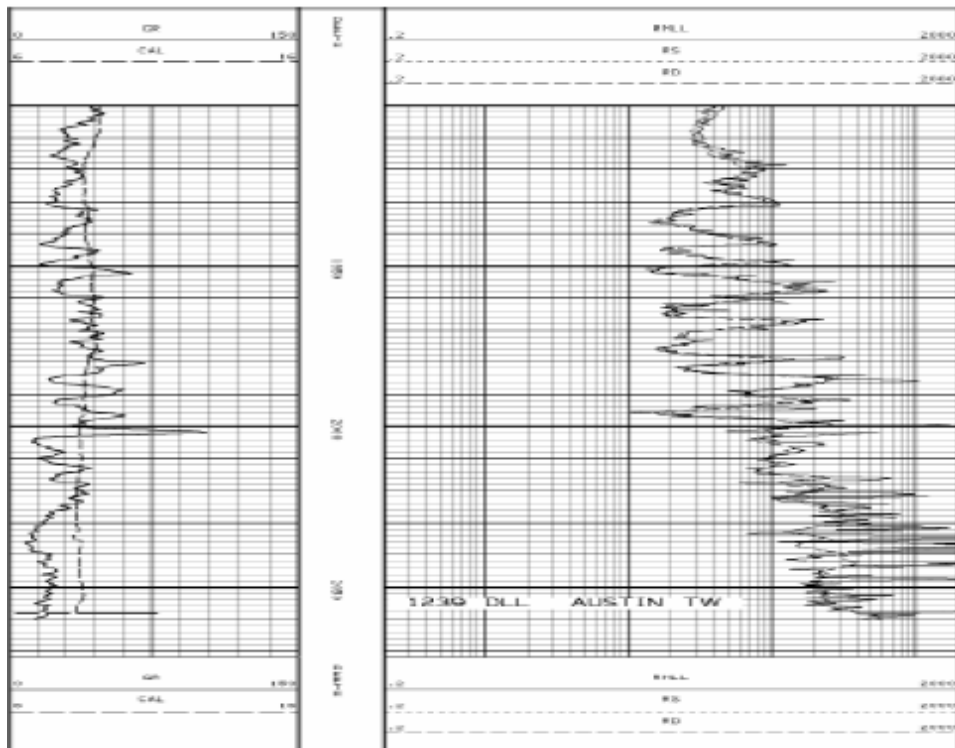
Standard 4 cycle log grid (DLL)

Micro Laterolog/Micro Spherically Focussed Logs

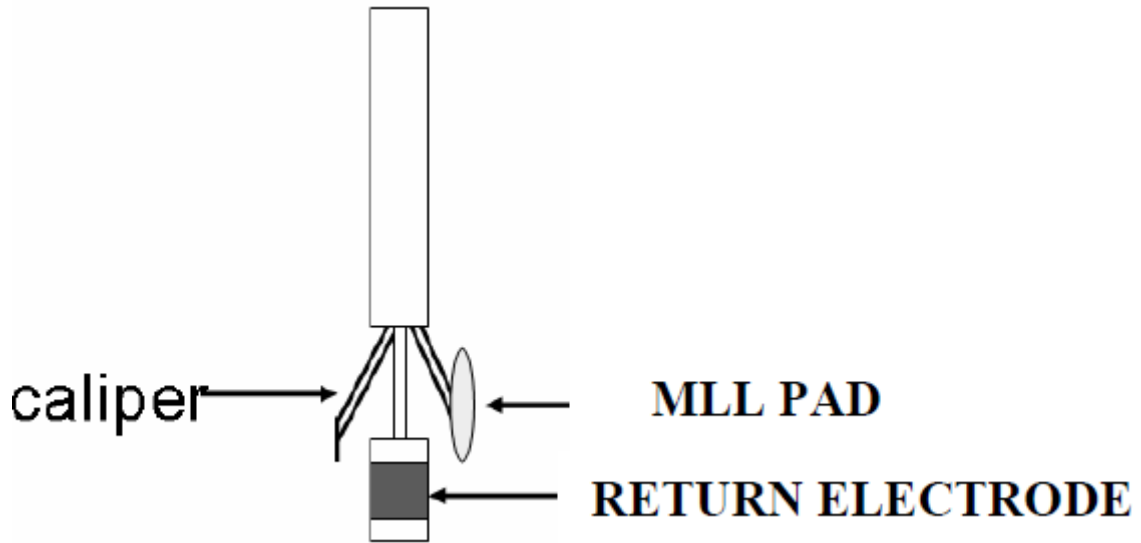MLL is pad device. MLL has small vertical resolution and depth of investigation. Used to determine R_{xo}, Exact thickness of formation beds.

R_{xo} can be used with archie's equation to calculate the saturation of the flushed zone

$$S_{xo} = \sqrt{(a / \emptyset^m) * (R_{xo} / R_{mf})}$$

Archie's equation, rewritten for saturation of the flushed zone, to determine moveable oil

caliper ← MLL PAD

← RETURN ELECTRODE

Theory

Current from a measure electrode is forced into the flushed zone by guard electrodes returning to the return electrode. The current to the measure electrode is measured as is the voltage with regard to the ground.

MICRO LATEROLOG DEVICE: a Pad Tool

$$R_{MSFL} = k\,\frac{V_{ref}}{I_0}$$

MSFL TOOL: a Micro-Laterolog Device
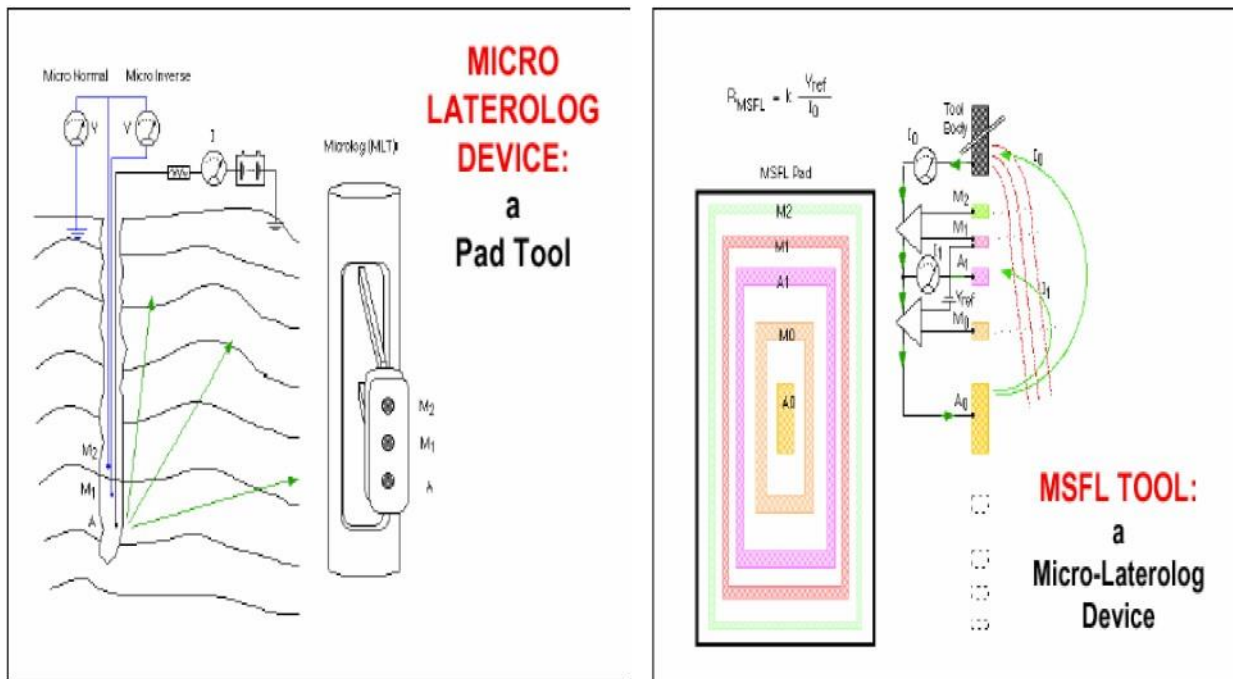
The MLL is a single tool contains an arm with the pad attached. The central electrode is the measure electrode. The eight other electrodes are guard electrodes.

INDUCTION LOGGING

PRINCIPLE

Induction tools are based on principles of electromagnetic induction. A magnetic field is generated by an AC electrical current flowing in a continuous loop/transmitter coil. The magnetic field from the transmitter coil induces ground loop currents in the formation. These ground current loops will in turn have an associated alternating magnetic field which will induce a voltage in the receiver coil, the magnitude of which is proportional to the formation conductivity.

- ✓ It works in oil based muds and air filled holes where latero tool fails.
- ✓ Tool accuracy is excellent for formations having low to moderate resistivity (up ~100 Ohm.m)
- ✓ The Dual Induction Latero (DIL) tool records three resistivity curves having different depths of investigation (ILD, ILM & LL3)
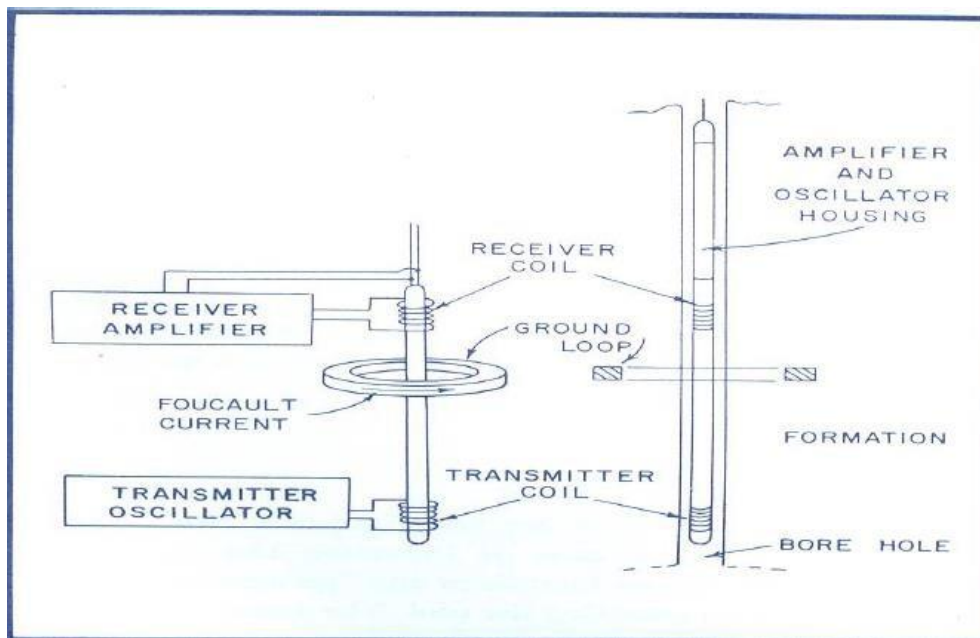
Principle of Induction Logging

Applications of Resistivity Logs
- ✓ True formation resistivity and flushed zone resistivity.
- ✓ Mud filtrate invasion profile.
- ✓ Quick look hydrocarbon detection.
- ✓ Indication of producible hydrocarbon
  Correlation of different formations

EXPERIMENT NO – 3

Computation of static temperature from the bottom hole temperature data

INTRODUCTION

The determination of physical properties of reservoir fluids, calculation of hydrocarbon volumes (estimation of oil and gas formation volume factors, gas solubility), predictions of the gas hydrate prone zones, well log interpretation, determination of heat flow density and evaluation of geothermal energy resources require knowledge of the undisturbed formation temperature.

In most cases bottom-hole temperature surveys are mainly used to determine the temperature of the earth's interior. The drilling process, however, greatly alters the temperature of formation immediately surrounding the well. The temperature change is affected by the duration of drilling fluid circulation, the temperature difference between the reservoir and the drilling fluid, the well radius, the thermal diffusivity of the reservoir and the drilling technology used. Given these factors, the exact determination of formation temperature at any depth requires a certain length of time in which the well is not in operation. In theory, this shut-in time is infinitely long to reach the original condition. There is, however, a practical limit to the time required for the difference in temperature between the well wall and surrounding reservoir to become vanishingly small.

HORNER METHOD

The Horner method is widely used in petroleum reservoir engineering and in hydrogeological exploration to process the pressure-build-up test data for wells produced at a constant flow rate. From a simple semilog linear plot the initial reservoir pressure and formation permeability can be estimated. Using the similarity between the transient response of pressure and temperature build-up, it was suggested that the Horner method be used for prediction of formation temperature from bottom-hole temperature surveys.

The well-known expression for the borehole temperature is($r = r_w$)

$$T_w(r_w, t_c) - T_i = -\frac{q}{4\pi\lambda} Ei\left(-\frac{1}{4t_{cD}}\right).$$

CONCOLUSION

A new method of determination of formation temperature from bottom-hole temperature logs is developed. It is assumed that the circulating mud temperature is constant. A semi-analytical equation for the transient bore-face temperature during shut-in is presented. At large values of shut-in and mud circulation dimensionless time the suggested equation transforms to the Horner formula.

Computation of permeability from charts and equations

Permeability

Permeability is defined as the ability of a reservoir to 'conduct' or 'transmit' fluids through the rock matrix: the flow capacity of a reservoir. While it is among the most important of reservoir properties to know, its measurement is also amongst the most difficult to acquire at the appropriate representative scale. Permeability is measured in darcies, reflecting the name of the person who first experimented with the flow of water through sand packs in 1856. Henry Darcy was a French municipal engineer based in Dijon for most of his career; he died in 1858, aged 55 years, just 2 years after completing his experiments in fluid flow (Figure 3.17). Darcy's simple empirical equation

Core permeability

Routine permeability measurements are made using the same core plug and flowing air or helium through the sample at a constant rate while varying the outlet pressure using different sized orifices. Measurements are made on both horizontal plugs (those drilled orthogonal to the core) and vertical plugs (drilled along the core); however, vertical measurements are usually only made on one tenth of the number of overall samples.

Log permeability

Permeability should only be calculated from logs when the formation is at irreducible water saturation. This condition can be determined using the bulk volume water (BVW) relationship:

$$BVW = S_w \times \phi$$

Porosity–permeability relationship

It its simplest form, permeability can be predicted from the log–linear rela- tionship with porosity determined from core analysis (Figure 3.18). Too often no more thought is given to the problem and only one relationship is propagated through the geological and petrophysical models. In reality, there is no causal relationship between porosity and permeability; rather, permeability is a function of grain size and sorting and the resultant pore throat size distribu- tion. However, permeability can also be related to many other properties, either empirically or intrinsically, including pore surface area, irreducible water saturation, relative permeability and capillary pressure. In well log anal- ysis, the only available predictor is porosity alone or possibly in combination with water saturation and volume of shale.
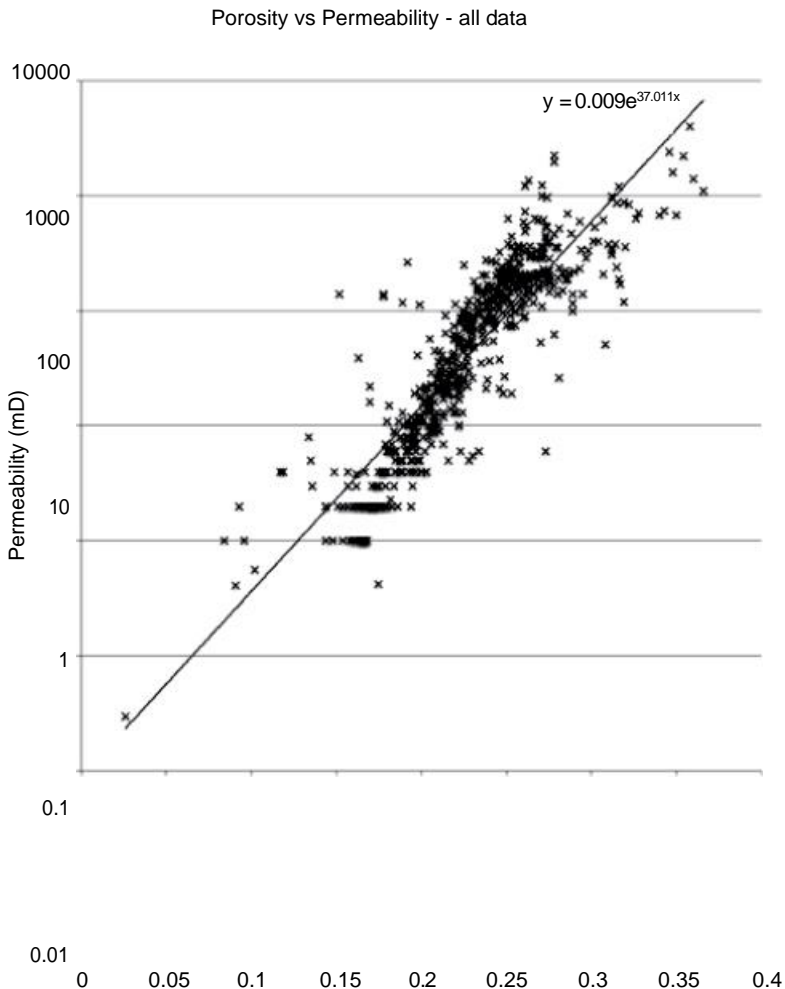
Porosity vs Permeability - all data

$y = 0.009e^{37.011x}$

Porosity (frac)

Figure 3.18 Example of a porosity–permeability cross-plot with a single linear *y*-on-*x* relationship described. The data distribution suggests that more than one lithofacies may be grouped together: try to partition the data to reflect geology.

Overburden correction and Klinkenberg effect

The old driller's adage that 'the only thing you know for sure about a core is that it used be in the ground' is especially true when one considers the changes that both rock and fluid undergo during coring, recovery and handling from rig to laboratory. The cutting of the core tends to introduce an invasion ring around the core that varies in thickness depending on the permeability. The release of pressure as the core is brought to the surface relaxes the grain fabric in most sandstones, increasing the pore volume and opening natural fractures
– the opposite of rock compressibility. Water and oil will tend to seep out of the core, while gas may often be seen bubbling on the surface of a core on the rig floor immediately after recovery.

Porosity and permeability need to be corrected from laboratory (ambient) to reservoir (overburden) conditions; permeability is also often corrected for frictional slippage of the medium (gas) used in making the measurement, the so-called Klinkenberg correction.

Summary

In some ways, this chapter is the key to petrophysics as it deals with the fundamental properties of the porous medium and the contained fluids; but it is also one of the most confusing, because of the variety of ways to define and measure different properties. It is important to define clearly whether you are working in a 'total' or 'effective' porous system and how you might propose to move from one to the other. Most petrophysicists would insist on starting in the 'total' domain because this is the easiest to calibrate with core measure- ments, but of course our logs are working *in situ* in the reservoir, where our measurements will be essentially effective. The debate revolves around the volume of water associated with detrital clays or microporosity. To ignore this clay-bound water is to overestimate the hydrocarbon, a cardinal sin especially when calculating oil or gas initially in place in a reservoir.

Computation of porosity of the formation using porosity logs
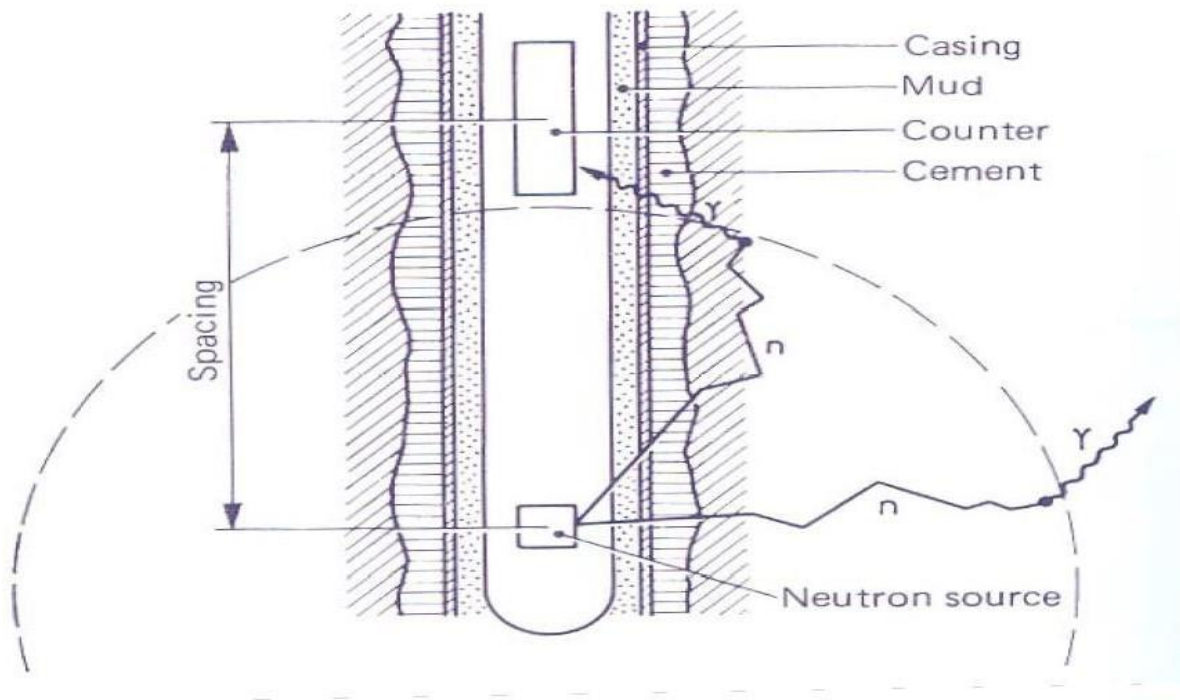
POROSITY LOG

Porosity values can be obtained from sonic log, a formation density log or a neutron log. In addition to porosity these logs are affected by other parameters, such as lithology, nature of the pore fluids, and shaliness. For more accurate porosity is obtained from combination of logs.

The readings of these tools are determined by the properties of formation close to the borehole. The sonic log has the shallowest investigation. Neutron and density logs are affected by a little deeper region, depending somewhat on the porosity, but generally within the flushed zone.

NEUTRON LOG
PRINCIPLE

In Neutron log we use a chemical source such as Americium-Beryllium/Neutron bulb which provides the emission of neutrons as continuous source of energy of about 4.5 MeV/14 MeV. When neutrons collides with nucleus of the atoms in the formation the neutron losses its energy and excites the nucleus of the atoms in the formation. When the exited nucleus returns back to its normal state, it emits Gamma ray characteristic to the atom. The analysis of the γ- ray spectrum identifies the composition of the elements in the formation: C, H, Cl, O etc. When the energy of the neutron reduces to thermal level and collides with Hydrogen atom its energy reduces to 0.025eV, also the neutrons are captured emitting gamma ray. Thus the uncaptured neutron reaching the detector is a measure of Hydrogen index of the formation.

Casing
Mud
Counter
Cement

Spacing

γ

n

n

γ

Neutron source

Porosity Determination

In determining the effective porosity in a shaly sand, the characteristics of the shale and shale volume must be well known. In hydrocarbon bearing shaly sand formations, the problem is further complicated by the effect of residual hydrocarbon on the porosity logs. Therefore, the porosities ϕd and ϕn in Equations (3 & 4) must have been corrected for the effect of residual hydrocarbon before dealing with the equations.

The density derived porosity ϕd is corrected from the residual hydrocarbons by the formula;

$$\phi d = [\delta ma - \delta + 1.07 (Rmf/Rxo)^{1/2}(1.11 - 1.24\delta h)]/(\delta ma - 1 + 1.07(1.11 - 1.24\delta h)) \quad (5)$$

Where; δma is the matrix density, δ is the log reading δh is the hydrocarbon density, Rmf is the mud filtrate resistivity, Rxo is the flushed zone resistivity, and ϕd is the residual hydrocarbon corrected porosity(Schlumberger, 1967).

The neutron derived porosity ϕn is corrected from the residual hydrocarbon by the formula;

$$\phi n = \phi na / \{(1 - Shr)[(\delta mf(1 - P) - \delta h - 0.3)/\delta mf(1 - P)]\} \quad (6)$$

Where ϕna is the apparent neutron porosity , P is the mud filtrate salinity (10^6 ppm) and ϕn the neutron porosity corrected from hydrocarbon effect (Dresser, 1982).

In order to determine the effective formation porosity, shale volume has to be accurately determined and the residual hydrocarbon effect removed. This is following the proposed scheme in **Fig. 3**. **Fig.** 4 depicts the effective porosity profiles for Wells 1 and 2 together with the shale volume. Depending on the available data, porosity could be determined either by neutron - density equations or by the proposed approach. In the case of neutron- density , the two Equations (3 & 4) are solved together and provide shale volume and effective porosity. In the

case of the developed approach, shale volume is calculated , the neutron and density porosity are corrected for the effect of residual hydrocarbons and then the effective porosity is calculated using the following formula (Schlumberger, 1987).

$$\phi_e = (\phi_d + \phi_n)/2 \quad (7)$$

The porosity profile which is shown in **Fig.** 4 is produced using Equation (6) after carrying out the corrections due to the presence of shale and hydrocarbon effect .

Find out the lithology of given data using cross plot

LITHOLOGY IDENTIFICATION:

Porosity determination using different logging devices relies on the knowledge of the rock type. In the case of the density tool, the density of the rock matrix must be known. The matrix travel time must be known to determine porosity from sonic log. In order to get porosity from neutron log the matrix setting for the neutron tool must correspond to the rock type. Determining these parameters is not much of a problem if one has good geological knowledge of the formation or if the lithologies encountered are simple, such as, for instance clean sandstone formation. If opposite is the case, if one is not sure about lithology, the best way will be to adopt graphical methods.

OVERLAY OF POROSITY LOGS ON A COMMON REFERENCE SCALE:

The three types of porosity log, which are available (sonic, density, neutron), are recorded in drastically different units (microseconds per foot, grams per cubic centimeter, and neutron counts in v/v or percentage porosity unit). However, the logs can be directly compared if calibrated on a common reference scale. The most widely used scale for this purpose is defined in terms of equivalent units of limestone percentage porosity. The density scale may be transformed by setting the grain density of calcite (2.71g/cc) to zero porosity, the fluid density (1.00 g/cc for fresh water) to 100% porosity and interpolating intermediate values. By an analogous procedure the transit time of the sonic log can be converted to the limestone porosity equivalents by setting the matrix transit times of calcite & pore fluid as the two porosity extremes for interpolation. Limestone porosity scale is the most common reference of the neutron logs and hence requires no scaling.

An overlay of any combination of the three porosity will give immediate indications of the lithology of logged units by virtue of the different responses of matrix minerals to the individual porosity logs. This point is illustrated by comparing the hypothetical response of a mixed sequence of lithologies to the density & neutron logs.

In log interpretation the main focus is to identify the formations susceptible of containing displaceable fluid. These formations are porous and permeable formations. Once the porous and permeable formations have been identified, the next great thing to do is to determine the nature of the fluid content in the pores. The fluid can be water or hydrocarbon, with rare instances of gases like nitrogen or carbon dioxide being present.

G.E. Archie's work relating permeability to porosity resulted in empirical relationships between resistivities, fluid types and porosity. In undisturbed formations, Archie's (empirical) law states that the ratio of formation resistivity to connate water resistivity (Ro/Rw) is constant. That is

$F = Ro/Rw$ (eqn1) Where:

- ✓ F is called the formation factor,

- ✓ Ro is bulk resistivity if pore space is filled 100% with brine (connate water),

- ✓ Rw is resistivity of the connate water itself. This relation applies best for clean (clay free) rocks of constant porosity when Rw < 1 Ohm-m, at 25C.

This is useful, except that Ro is not really measurable in the field. But the relation can be made useful because Archie also found that this resistivity ratio (i.e. F) changes consistently as porosity changes.

- ✓ Formation factor and porosity are usually related via

- ✓ $F = a / phi^m$

     (eqn 2)
- ✓ where phi is porosity expressed as a percent (a value between 0 and 1).
- ✓ **a** is a constant between 0.6 and 1.5. It is often left at 1.

   - ✓ **m** is the cementation exponent and is usually 1.5-1.8 in sandstones and 2.0 in limestones, dolomites and tight consolidated sandstones.

     2.15

   - ✓ One example of a particular version is $F = 0.62 / phi^{2.15}$ (the so-called "Humble relation", suitable for many granular rocks).

AN ALTERNATIVE RELATION IS:

$(1.87+0.019/phi)$

- ✓ $F = 1 / phi^{(1.87+0.019/phi)}$ (The Shell relation, best used for low-porosity carbonates).

Finally, water saturation (S_w) and formation resistivity were also found to be related. Water saturation is the percentage of the pore space filled with water, which is of course important when evaluating a potential hydrocarbon reservoir. Sw=1 means all fluids are water 100% and Sw=0.1 means 10% of fluids are water, implying 90% are non-conductive or oil/gas. The relation is $S_w = (R_0/R_T)^{1/n}$ (eqn 3) where

- ✓ **n** is a saturation exponent, usually close to 2.0. (**n** is not porosity in this relation),

- ✓ **Ro** = rock resistivity with 100% brine for fluid

- ✓ **Rt** = true resistivity (with hydrocarbons and water in pore space).

Now the Archi equation relating quantities of interest to measurable quantities can be

derived based upon eqns 1, 2, 3:

$$S_w = (FR_w/R_T)^{1/n} \quad \text{(eqn 4)}$$

This relation is commonly used for oil / gas reservoir characterization. Three parameters must be measured: (i) porosity, (ii) resistivity of the undisturbed formation, and (iii) resistivity of connate water. Symbols are phi, R_t and R_w respectively. R_w can be obtained from:

- ✓ Water catalogues of the area you're working in;
- ✓ Laboratory analysis of samples extracted from the formation rocks;
- ✓ Obtainable from the spontaneous potential or SP log;
- ✓ "Apparent" water resistivity from R_t = F * Rwa when Sw = 1, e.g. in "clean water sands";
- ✓ By relating invaded & uninvaded resistivity in **clean zones**;
- ✓ From resistivity - porosity crossplots;
- ✓ From Rwa - SP crossplots.

Rt is true resistivity of undisturbed formation. Of course drilling disturbs the formation, so choosing the right tool and interpreting various resistivities is important. Methods must account for bore hole environment, invasion, effects of adjacent beds, and technical aspects of tools themselves.

In the oil / gas context, porosity phi is obtained from the porosity well logging tools, or possibly from resistivity where Sw is known to be 100%. Porosity logging tools are also used in hydrogeology and engineering situations, though this is not routine as in the oil / gas industry.

EXPERIMENT NO – 7

Computation of Volume of shale from integrated approach

DETERMINATION OF SHALE VOLUME AND POROSITY

The way shale affects a log response is controlled by type of shale, shale volume and mode of shale distribution. There are two types of shale, effective shale (montmorillonite and bentonite) and passive shale (kaolinite and chlorite) . Effective shale has significant CEC (cation exchange capacities), while passive shale has essentially zero CEC. Effective shale can be identified by most of the shale indicator tools, whereas, passive shale is recognized only by neutron tool.
This means that the latter type of shale is difficult to distinguish from the sand on logs other than neutron. Regional experience is required to determine the mode of shale distribution. Derived log porosity value is composed from two terms, an effective porosity term and a shale porosity term (shale porosity and shale volume). Therefore, in order to obtain the effective porosity of a shaly sand , both shale volume and shale porosity should be accurately defined.

Shale Volume Determination

The determination of shale content is necessary to accurately derive porosity from porosity logs. Shale volume may be determined easily by one of three techniques. These are the gamma ray log, the resistivity log, and the density-neutron logs. **Fig. 2** .illustrates the available log data for Well 1 , Gulf of Suez. In this case, shale volume will be calculated using three techniques. The lowest value of shale volume will be used in the calculation, in order to minimize errors due to the possible existence of passive shales and radioactive sands.

Gamma Ray Shale Volume The gamma ray (GR) has been used as one of the independent shale indicators in the evaluation of shaly sand. In the qualitative evaluation of shale content, it is assumed that radioactive minerals other than shale are absent.

Shale volume ,Vsh, is derived from GR response through the relationship;

$$Vsh = 0.33 (2^{\,2\,I_{GR}} - 1) \qquad (1) \; (\,Dresser, 1982\,)$$
$$and \; I_{GR} = (\,GR\text{-}GR_{cl}\,)\,/\,(\,GR_{sh} - GR_{cl}\,)$$

Where GR_{cl} is GR against clean sand , GR_{sh} is GR against adjacent shale layer and GR is the log response for the target layer. Equation (1) is used to determine shale volume using the GR readings for shaly sand reservoirs encountered in well 1, Fig. 1. The presence of other radioactive minerals will cause the calculated shale volume in this case to be too high. Therefore, it is not recommended to rely on GR only and go for another technique to determine the accurate shale volume. **Figure** 3 includes the GR as first option , shale volume determination, of the developed approach to evaluate shaly sand.

Resistivity Shale Volume The use of resistivity log data as a shale indicator is dependent on the contrast of the resistivity response in shale and in a clean pay sand. Dependent on porosity, lithology and water salinity different resisitivity contrasts are normally seen. This means that the calculated shale volume from resitivity may be too high, too low or both.
Poupon et al (1970) proposed the following relation for estimating shale volume Vsh from resistivity data,

$$V_{sh} = [\,(R_{sh}\,(\,R_{max} - R_t\,))\,/\,(R_t\,(\,R_{max} - R_{sh}\,))\,]^{\,1/b} \qquad (2)$$

Where R_{max} is maximum resistivity in clean pay sand , R_t is the shaly sand layer resistivity and b is an empirical constant which for the reservoir rock studied was assumed to be 1.4. Shale volume calculated by **Eq**. 2 is considered in the algorithm shown in **Fig** 3. In this algorithm, Rsh is taken against the near by shale while Rmax is measured against the most clean oil sand for Wells 1 and 2.

Neutron- Density Shale Volume   The neutron - density crossplot can be used to determine shale volume and effective porosity if the zone is composed of only effective shales and sands. The presence of passive shales or other reservoir rocks will result in a too high calculated shale volume and too low effective porosity.

Shale volume (Vsh) and effective porosity (ϕe) are calculated by the solution of the simultaneous equations 3 and 4 for density and neutron responses.

$$\phi d = \phi e + Vsh\,\phi dsh \qquad (3)$$
$$\phi n = \phi e + Vsh\,\phi nsh \qquad (4)$$

ϕ_d is the density derived porosity, ϕ_n is the neutron derived porosity, ϕ_{dsh} is shale density porosity, ϕnsh is shale neutron porosity and ϕe is the shaly sand effective porosity. These equations are written assuming that neutron and density responses are not affected by the mode of shale distribution. The calculated shale volume can be optimistic or pessimistic depending on the considered matrix parameters. **Fig.** 3 illustrates flow chart for the developed approach to calculate shale volume using the density- neutron crossplot together with the GR and Resistivity methods. In this approach three values of shale volumes are produced , but the lowest value is considered the shale volume value in the consequent calculation of porosity and hydrocarbon saturation. **Fig.** 4 shows shale volume distribution profiles for Well 1 and Well 2 . From **Fig**.4, it is obvious that the shale is a laminated shale with sand layers containing different percentages of shales.

CONCLUSIONS

1- Evaluation of shaly sands is somewhat complex. All logging responses and interpretation techniques are influenced by the shale. Regardless of the basic assumptions, most of the shaly sand models employ a weighted average technique to account for the relative contributions of the sand term and the shale term to the overall shaly sand response.

2- The developed integrated approach to determine shale volume and hydrocarbon potential in shaly sands can provide the user with the most important petrophysical parameters; shale volume, effective porosity, water saturation, and movable hydrocarbon potential.

EXPERIMENT NO – 8

Find out hydrocarbon saturation from Archie equation & Indonesian equation

DETERMINATION OF WATER SATURATION

Shaly sand corrections all tend to reduce the water saturation relative to that which be calculated if the shale effect is ignored in the evaluation processes. Over the years, for shaly sands a large number of models relating fluid saturation to resistivity have been developed according to the geometric form of existing shales (laminated, dispersed and structural). All these models are composed of a shale term and a sand term. The shale term may be independent or not of the sand term. All models are reduced to the clean sand model when the volume of shale is insignificant. For relatively small shale volumes, most shale models might yield quite similar results (Waxman and Smits, 1968 ; Poupon et al , 1970; Bussian, 1984 and Schlumberger, 1987).

The comparison of the various water saturation equations in shaly sand shows that: 1) The clean sand equation does not compensate for clay conductivity, the water saturation it computes is too high; 2) Simandoux or Indonesia equation (Dresser, 1982) is essentially applicable to laminated clay models, with some adaptation for non linear behavior of shale electrical properties and 3) Waxman- Smits or Dual Water model (Clavier et al , 1977) is essentially designed for the case of dispersed or structural clay models and as they account for the effects occurring in the pore space, they provide lower water saturation than laminated models (DeWhite, 1950;, Simandoux, 1963; Waxman and Smits, 1968; Fertl and Hammack, 1971; Clavier et al, 1977 and Dresser, 1982).

Local experience in the Gulf of Suez for Wells 1 and 2 showed that the geometric form of the existing shale is a laminated one. Consequently, the Indonesia equation was used to calculate water saturation in this shaly sand case. Indonesia Equation is defined as ;

$$1 / R_t = [((V_{sh}^{\ 1-Vsh/2}) / R_{sh}^{\ 0.5} + \phi_e^{\ m/2}))^2 \cdot S_w^{\ n} \qquad (8)$$

For the case where a = 0.81 and m = n = 2 Equation (8) will take the form;

$$S_w = [1 / ((V_{sh}^{\ 1-Vsh/2} / R_{sh}^{\ 0.5}) + \phi_e / (0.81 R_w^{\ 0.5}))] \cdot 1/R_t^{\ 0.5} \qquad (9)$$

Equation (9) represents the basic formula to determine the water saturation and hydrocarbon saturation (1-Sw) for the studied reservoirs in the two wells. The proposed approach to

evaluate shaly sand uses Equation (9) to determine the hydrocarbon potential. **Fig. 5** illustrates water and hydrocarbon volume profiles for the studied reservoirs ,Wells 1 and 2, derived from the application of Equation (9). Against shale streaks, both water saturation and hydrocarbon saturation are not calculated, only for layers of shaly sand (Vsh less than 20%) are the water saturation and hydrocarbon saturation profiles are produced for the corresponding section for Wells 1 and 2 in the Gulf of Suez. It is worth to emphasize that the effective porosity, ϕe, in Equation (9) is the porosity corrected for shale and residual hydrocarbon effects. In this way, the integrated approach provides the user with a good idea about the formation lithology and an accurate determination of the hydrocarbon potential and effective porosity of the shaly sand formation. It is easy to change the input parameters and equations depending on the available data and also it is designed to quit or enter the program at any desired stage.

"THE ARCHIE EQUATION"

In his classic paper, Archie (1942) proposed two equations that described the resistivity behavior of reservoir rocks, based on his measurements on core data. The first equation governs

the resistivity of rocks that are completely saturated with formation water. He defined a "formation factor", F, as the ratio of the rock resistivity to that of its water content, Rw, and found that the ratio was closely predicted by the reciprocal of the fractional rock porosity powered by an exponent, he denoted as m. The value of m increased in more consolidated sandstones and so was named the "cementation exponent", but seemed to reflect increased tortuosity in the pore network. For generalized descriptors of a set of rocks with a range of m values, workers after Archie introduced another constant, "a". In a second equation, Archie described resistivity changes caused by hydrocarbon saturation. Archie defined a "resistivity index", I, as the ratio of the measured resistivity of the rock, Rt, to its expected resistivity if completely saturated with water, Ro. He proposed that I was controlled by the reciprocal of the fractional water saturation, Sw, to a power, "n", which he named the "saturation exponent.

The two equations may be combined into a single equation, which is generally known as "the Archie equation". Written in this form, the desired, but unknown, water saturation (Sw) may be solved.

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

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

$$ S_w = \left[\frac{a}{\Phi^m} * \frac{R_w}{R_t} \right]^{1/n} $$