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A Review on Models for Evaluating Rock Petrophysical Properties

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Abstract

The evaluation of subsurface formations as applied to oil well drilling started around 50 years ago. Generally, the curent review articule includes all methods for coring, logging, testing, and sampling. Also the methods for deciphering logs and laboratory tests that are relevant to assessing formations beneath the surface, including a look at the fluids they contain are discussed. Casing is occasionally set in order to more precisely evaluate the formations; as a result, this procedure is also taken into account while evaluating the formations. The petrophysics of reservoir rocks is the branch of science interested in studying chemical and physical properties of permeable media and the components of reservoir rocks which are associated with the pore and fluid distribution. Throughout recent years, several studies have been conducted on rock properties, such as porosity, permeability, capillary pressure, hydrocarbon saturation, fluid properties, electrical resistivity, self-or natural-potential, and radioactivity of different types of rocks. These properties and their relationships are used to evaluate the presence or absence of commercial quantities of hydrocarbons in formations penetrated by, or lying near, the wellbore. A principal purpose of this paper is to review the history of development the most common techniques used to calculate petrophysics properties in the laboratory and field based primarily on the researchers and scientists own experience in this field.

Keywords: Petrophysical Properties, Hydrocarbon, Reservoir, Shale Volume, Porosity, Water Saturation, Permeability, Petroleum Technology, Interpretation.

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1- Introduction

Interpretation of well log results is one of the important processes for engineers and geologists to classify the petrophysical properties. The log data is important in reservoir engineering calculations, especially in the estimation of the reserve. The best interpretation for any structure of interest is influenced by the quality and quantity of log data available to analysts and the type of problem [1]. Generally, there are two types of data when analyzing these properties; instrumental methods that measure the properties vs. depth, which are called logs; and real samples that exactly represent the formation that we are dealing with, such as cores and cuttings [2] . The Cross plot methods are common means to display the effect of combinations of logs on lithology and porosity, and they give a visual idea of the type of lithology mixtures [3].

The quantitative estimation of a hydrocarbon unit in any formation requires a correct estimate of shale volume, which causes a blockage to the pore space and decreases the amount of permeability, which, as a result, decreases the reservoir quality [4]. There are several methods for calculating porosity, including laboratory testing and/or log data. The precision of porosity found from drill cuttings can be incredibly affected by the size of the cuttings and desaturation time [5]. Likewise, log analysis has been utilized for porosity determination. One of the significant parts in formation evaluation is the water saturation (Sw) that is still difficult regarding well logging analysis. A water saturation estimation considering resistivity and porosity was first proposed for clean sand development and was named the Archie formula. After that, a quantity of significant water saturation models emerged on traditional logging data for shale-bearing sands, such as the Simandoux model , modified Simandoux model [6], Indonesian model, total shale model, modified total shale model , and dispersed clay model , and dual water model. That leads to good results for clean sandstone reservoirs. For petroleum engineers, permeability is a main input and an important key in reservoir management as well as in development. For example, when selecting the optimum production rate for the field and water injection patterns [7]. Almost all analyses of petroleum reservoirs include a calculation of net pay. The total reservoir material that will flow an economically feasible amount of hydrocarbon under a specific production process is known as net pay [8]. If unquestioned, the significance of net pay thickness is with regard to hydrocarbon in situ and reserve estimation [8]. To differentiate between net pay intervals and non-net pay intervals, there isn't a standard procedure or approach, though.

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2- Petrophysical Properties Determination Techniques

A variety of parameter techniques were applied to the petrophysical parameters. A brief review of these methods is discussed in the following subdivisions (see Fig. 1).

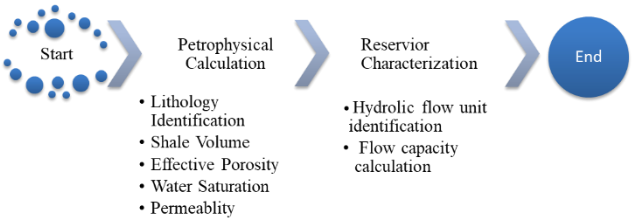

Fig. 1. Petophysical Analysis and Flow Units Characterization

2.1. Shale volume determination

One of the most public problems in formation evaluation is the impact of shale in reservoir rocks. A precise determination of formation porosity and fluid saturation in shaly sand is exposed to several uncertain parameters, all of which are prompted by the presence of shale in the pay formation.

To handle this issue in the shale sand reservoir. An integrated calculation is given to determine the exact value of shale volume from various shale indicator tools, and after that, the effective porosity is determined. can summarize the methods that are used to determine the shale volume:

De Witte, presented his model for dispersed shale considering very shaly formations. This model can be simplified to characterize low shale formations having low values of water resistivity, In light of laboratory research and field knowledge [9].

Winsaur et al., studied the ionic conductivity in double layers in reservoir rocks and presented a model for charge scattering in shaly sands. He defined the increment in the obvious conductivity of shale because of the way that clays add to the total conductivity of the rock while the rock structure is nonconductive [10].

Waxman and Smits, established the conductivity model of clay-bearing sandstone to explain the effects of clay additional conductivity. It assumes the same formation factor clay has a parallel conductive path to the pore water. The relationship can be described by the following equations [11]:

$$C_o = \frac{1}{F}(C_W + C_{ex}) \quad (1)$$

$$C_{ex} = BQ_v \quad (2)$$

$$B = 3.83(1 - 0.83e^{-\frac{Cw}{2}}) \quad (3)$$

$$Qv = \frac{CEC(1-\emptyset t)\rho_G}{\emptyset t} \quad (4)$$

Where Eq. 1 is an empirical equation derived from Na+ at 25°C, The Waxman-Smits model has the ability to capture the nonlinear behaviors of the saturated rock conductivity vs. the pore-water conductivity at low salinity.

Poupon and Leveaux, developed a Indonesia model to calculate high amount of shale and fresh water saturation the equation used the computer - made cross plot to between the water saturation (SW) and true resistivity of formation ,the range of shale recorded (30-70%) [12].

$$\frac{1}{\sqrt{Rt}} = [\frac{Vcl^d}{\sqrt{Rclay}} + \frac{\emptyset^{m/2}}{\sqrt{aRw}}]Sw^{n/2} \quad (5)$$

Where; Vclay is volume of shale; Rt, formation true resistivity; Rw, formation water resistivity; a, tortuosity, ϕ, porosity; Sw, water saturation.

Clavier et al., developed equation was used to estimate shale volume from gamma ray, density and neutron-density methods [13,14] were utilized to compute total and effective porosities for older rocks. Clavier neutron-density equation [15]:

$$Vshale = \frac{NPHI_{log} - NPHI_{ma} + M1(\rho_{ma} - \rho_{log})}{NPHI_{shale} - NPHI_{ma} + M1(\rho_{ma} - \rho_{shale})} \quad (6)$$

Where:

$$M = \frac{NPHI_f - NPHI_{ma}}{\rho_f - \rho_{ma}} \quad (7)$$

Thomas and Stieber, this strategy is used to determine shale distributions, sand fractions, and sand porosity. It was chosen to account for thin-bed properties on log measurements in thin sand, Fig. 2 is a geometrical solution of the Thomas–Stieber method for laminated sands and shales with sands containing dispersed and/or Structural shale which is a base case in this interpretation. The bottom vertex of the lower triangle is the dispersed shale endpoint where the clean sand pore is filled with dispersed shale and top vertex of the upper triangle is the structural shale endpoint where the grain of the original sand is completely replaced with shale [15, 16].

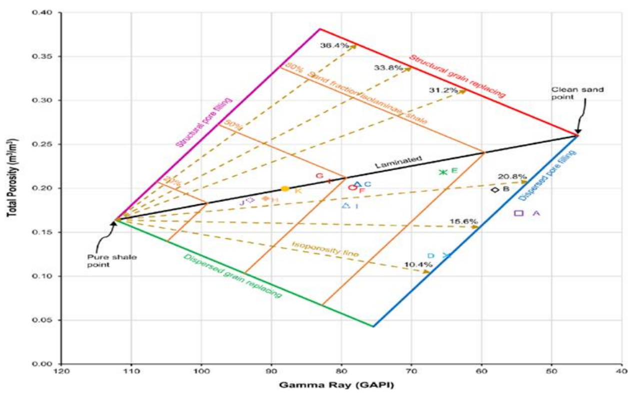

Fig. 2. Thomas and Stieber (1975) Geometrical Solution [7]

Fertl and Chilingarian, presented the standard Shaly clastic reservoir rocks commonly hold variable amounts of clay minerals. The basic properties of the most common public clay minerals vary significantly, including chemical composition, matrix density, photoelectric cross-sections, hydrogen index (HI), cation exchange capacity (CEC), potassium, thorium, and uranium (in present unit) [17].

Mohammadhossein Mohammadlou et al., in this study, reservoir clay volume is calculated using fine-grained clastic sedimentary rocks composed of clay and pieces of other minerals, such as carbonates and siliciclastic. The NMR log is used as an easy tool to assess the veracity of the shale volume estimate from gamma-ray and spectral gamma-ray logs (most clay minerals contain variable amounts of water trapped in the mineral structure). In the lowermost reservoir region, the inconsistency between the shale quantities calculated by different approaches is substantial. SEM analysis was used to detect the mineralogy and mineral volume fractions in order to solve the problem. The SEM data was used as a reference point for calibrating the spectral gamma-ray log in order to determine the shale volume [18].

2.2. Porosity Determination methods

Porosity is the ratio of the pore or void volume to the macroscopic or bulk volume, and there are many types of porosity. The average flux in pores is associated with the bulk Darcy flux. It varies between 0.1 and 50%. The porosity is directly measured in the laboratory by (collecting cuttings) or from drilling data.

2.2.1. Porosity measured in the laboratory by (collecting cutting)

Onyia, the shown relationship between UCS and porosity utilizes Warren's roller cone penetration rate model. For this situation, the UCS is determined straight from log and drilling data. The Onyia strategy is used on a variety of lithologies, including both shale and sandstone [19].

Vojko Matko, the Stochastics Method was utilized to assess porosity; this method employs a very sensitive sensor with less uncertainty in measuring results and less effect from disruptive noise signals. It is much simpler than the helium pycnometer approach. Furthermore, no water is placed on the material. The soil or rock sample is instead immersed in water. Due to stability and long-term repetition, the porosity sensor employs sensitive capacitive-dependent crystals (40 MHz with stability of 1 ppm in the temperature range of 5 to +55 °C). The direct digital method (DDM) reduces the influence of disturbances, which reduces the uncertainty of the outcome [20].

Erfourth et al., this technique uses UCS data that has been collected from laboratory analysis on core, cast, and tuff samples to compute the porosity. The Onyia method yields much higher porosity values for low UCS sectors than the Erfourth method, but the Erfourth method becomes inexact for high UCS sectors. The Onyia correlation also becomes relatively constant at a UCS value of 100 MPa [21].

D El Abassi, A Ibhi, et al., the scientists used an ultrasonic reflectivity technique to measure the porosity, tortuosity, and longitudinal ultrasound velocity of meteorites in this study. They measured the ultrasound reflection coefficient of the surface of polished meteorite thin plates at two oblique angles of incidence and normal incidence. In comparison to other existing laboratory procedures, determining porosity with this method is simple, quick, inexpensive, and non-destructive. In the analyzed meteorite specimens, they discovered a good linear association between density and porosity, as well as a good linear correlation between the logarithm of porosity and the longitudinal velocity of ultrasound. This suggests that the porosity of these meteorites can be estimated using a simple linear mathematical relationship based on the longitudinal velocity of ultrasonic vibrations [22].

2.2.2. Porosity measured in the laboratory from Drilling Data

Westbrook and Redmond, this study applied a single-unit arrangement of capillary diaphragm. This technique provided a means to measure the bulk volume of a great number of particles, such as drill cuttings. This method is quite accurate and reduces errors present in former solutions to measure the porosity of drill cuttings [23].

Horsund Chang et., the researchers in this study used the Gamma Ray method to collect data from both core and cuttings analyses. To create precise correlations for sandstone and shale porosity versus UCS and make correlations between the UCS and porosity in sandstone and shale lithologies [24].

Siddiqui et al., in this study, applied (histogram-based analysis) techniques using laboratory tools to crush the plug into cuttings with various mesh sizes to show the full description of a carbonate core plug, and afterward, the cutting samples were scanned with a CT-scanner to determine (bulk densities and porosities) [25].

Lenormand and Fonta, in this study, the (a medical-based CT-scan method) was re-examined and showed that the accuracy decreased for the cuttings with a diameter of less than 2.5 mm. In order to obtain consistent porosity from cutting with the sizes down to 0.5 mm, [26].

2.3. Water saturation Determination methods

Water saturation dispersion is the main factor in formation evaluation. The right estimation of water saturation is required for a correct volumetric calculation, which is of commercial interest. Recognizing the difference between hydrocarbons and water involving the reservoir is critical. This can be done by determining the water saturation in the area of interest since the whole saturation in the reservoir is 100%. The techniques that are used to determine the water saturation are:

Archie, the associations of the electrical resistance of fluids in porous media and porosity were discovered. He converted the analysis of well logs from qualitative analysis to quantitative analysis by proposing the in-situ equations to estimate the fluid saturations. Table 1 Values of Archies' parameters [15].

$$Sw = \left(\frac{aR_w}{\emptyset_t^m R_t}\right)^{\frac{1}{n}} \quad (8)$$

Table 1. Values of Archies' Parameter for Different Lithologies [27]

Description of rocks	a	m
Weakly cemented detrital rocks, such as sand ,sandstone ,and some limestones with a porosity range from 25 to 45 % usually Tertiary in age.	0.88	1.37
Moderately well cemented sedimentary rocks including Sandstones and limestones, with a porosity range from 18 to 35% usually Mesozoic in age.	0.62	1.72
Well–cemented sedimentary rocks such with porosity in the range 5 to 25 %.	0.62	1.95
Highly porous volcanic rocks, such as tuff , aa ,and pahoehoe , with porosity in the range 20 to 80 %.	3.5	1.44
Rocks with less than 4% porosity , including dense igneous rocks and metamorphosed sedimentary rocks.	1.4	1.58

Dunlap, in this method found the water saturation factor "n" can vary (from 1.18 to 2.90) based on core rock sort and different saturation methods [28].

Dewitte, established a means to determine water saturation in dispersed shaly formations. The method known as the clay slurry model involves the clay dispersed in the pore space with a clean sand pore structure. In other words, the clay minerals in the formations are expected to exist in a slurry with the formation fluid. This model is given by the following equation [29]:

$$Sw = \frac{1}{1-q}\left(\sqrt{\frac{aRw}{\emptyset_{tm}^2} + \frac{q^2}{4}} - \frac{q}{2}\right) \quad (9)$$

Wyllie and Rose (1950), in the numerical sense, assumed factor (M) can range between one and infinity; however, it lies between (1.3 and 3.0) depending on the first experimental by Archie 1942 [28].

Hingle, suggested the graphical solution. It is the first commonly used solution to solve Archie's equation. To interpret this method, use a specially designed graph paper and look for the cementation exponent value, m, where the y-axis varies with that value. the hingle plot (Fig. 3) assume the saturation exponent and cementation exponent both equal to 2.0 and rewrite the Archi formula in form [30]:

$$\frac{1}{\sqrt{Rt}} = Sw \frac{1}{\sqrt{Rw}} \emptyset \quad (10)$$

Keller, showed that electrical resistivity experiments treated sandstones. The research introduced the exponent "n" range in (1.5 to 11.7) depending on how the cores were dealt with [31].

Dobrynin, presented with a factor (m) value, it can be determined as a function of lithology and pressure. Furthermore, the greatest variety in (m) relies upon the quantity of small conductivity channels in the rock [32].

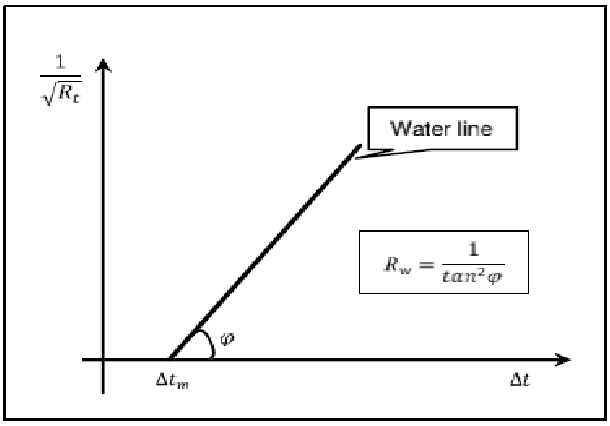

Fig. 3. Hingle Plot [30]

Simandoux, developed a model to predict water saturation during the production of shaly sand. The model was created as a consequence of laboratory tests done on a physical A reservoir model made of synthetic sand and clay was created in the Institute of English Petroleum (IFP). the Simandoux still One of the most common models used for water saturation models and a very important basis for subsequent research in this field. The Simandoux equation [29]:

$$Sw = \frac{aRw}{2\,\emptyset^m}\left[\left(\frac{-Vsh}{Rsh}\right) + \sqrt{\left(\frac{Vsh}{Rsh}\right)^2 - \left(\frac{4\emptyset^m}{aRwRt}\right)}\right] \quad (11)$$

Buckles, after Buckles produced this technique to calculate average water saturation, he concluded that the invention of water saturation and porosity in intervals at irreducible water saturation would be a constant related to pore surface area [6].

Pickett's, this strategy is based on the Archie equation, which effectively used to predict main parameters (a and m) in clean formation and relies on a graphical plot to include resistivity at the water zone vs. porosity to approximation factor (m) from data of well logs (Fig. 4) [33, 30].

$$\log Rt = -m log\emptyset + \log\left(\frac{Rw}{Sw^n}\right) \quad (12)$$

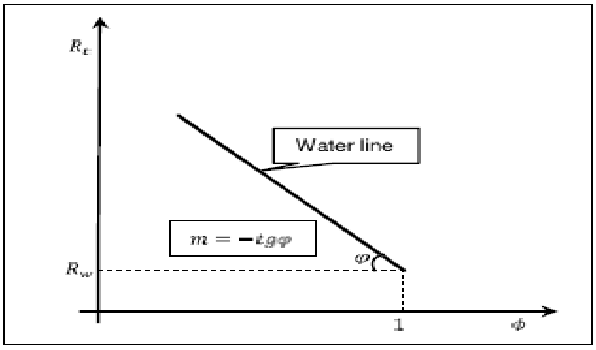

Fig. 4. Pickett Plot [30]

Waxman and Smith, established a dual water model depending on the CEC of shale. The (CEC) is measured as the main shale properties. which is expressed in milli equivalent unit pore volume of pore fluids, Qv (meq/cc).

In a general laboratory study, a saturation resistivity relationship for shaly formation was found that linked the resistivity impact of the shale to the (CEC) of the shale. (Waxman–Smits relationship) [34, 35].

Morris and Biggs, the researchers in this research reached the conclusion that the porosity-water saturation produced was a fraction of bulk volume water, BVW. used as a constant (often denoted as "Buckles number"). This constant is used not only to classify transition zones from zones at irreducible saturation, but also to approximation permeability. A Buckles plot is a plot of water saturation (Sw) vs. porosity (Fig. 5). Contours of equal bulk volume water (BVW) are drawn on the plot.

- Points plot on a hyperbolic BVW line where the formation is near immobile water if the points come from a reservoir with consistent pore type and pore geometry.
- Points scatter on a Buckles plot where the formation falls below the top of the transition zone [36].

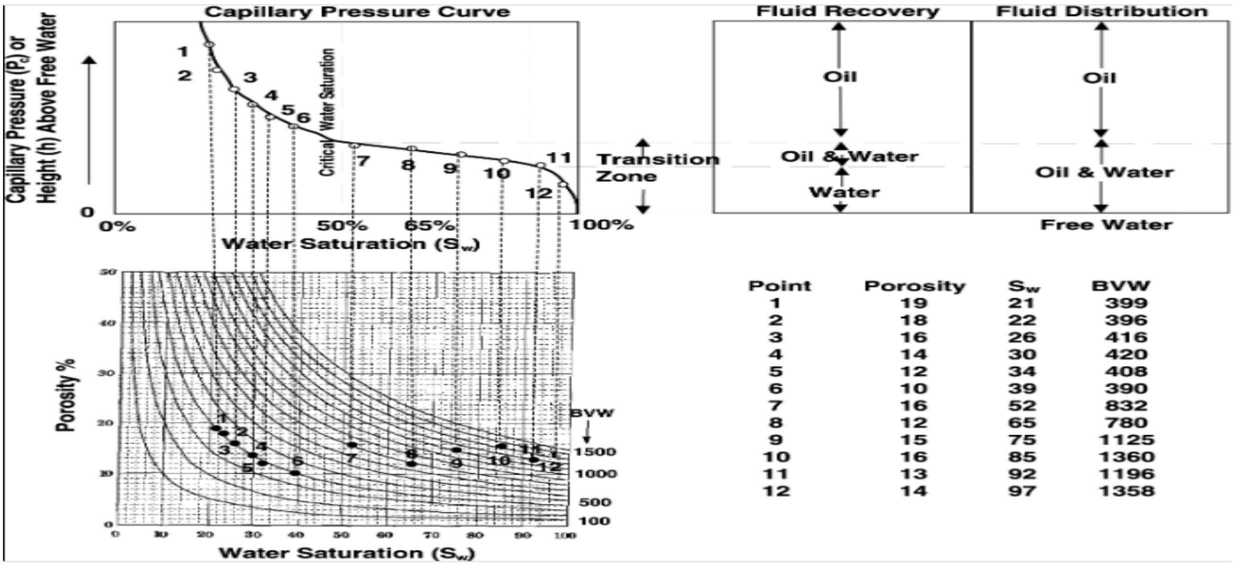

Fig. 5. Buckles Constant Relates to Capillary Pressure, Fluid Distribution, Fluid Recovery and Porosity in a Reservoir [36]

Poupon and Leveaux, the Formulated Indonesia model [37];was established to remove the limitations of other techniques in reservoir studies when determine water saturation in laminated and shaly formations The Indonesia model was developed by field observation in Indonesia, rather than by laboratory experimental measurement support, also does not particularly assume any specific shale distribution. The Indonesian model also has an extra feature as the only model considered the saturation exponent (n). This model is given by the following equation [29]:

$$\frac{1}{Rt} = Sw^{\frac{n}{2}}\left(\frac{Vsh^{1-\frac{Vsh}{2}}}{\sqrt{Rsh}} + \left(\frac{\emptyset^{\frac{m}{2}}}{\sqrt{aRw}}\right)\right) \quad (13)$$

Miyairi and Itoh, depended on the Poupon et al. model (1971) for shaly sands to produce a method to obtain three shaly sand factors: a, n, and m. This strategy can be defined by using several crossplots, like true resistivity formation versus porosity (R, vs p) and true resistivity formation versus porosity of the shaly formation (R, vs cpst) [38].

Ellis & Singer, found The value of (n) is measured from core sample data laboratory and (n) is estimated from slope line for resistivity index (Rt/Ro, where Ro is the water filled resistivity and Rt is the true resistivity) on a log-log scale with water saturation measurements [39].

Yang Kebing, Xie Li, et al., based on Archie's formula and the formation invasion model, the scientists in this study developed a formula for calculating reservoir water saturation by radial resistivity ratio under the most extensive conditions. The use of radial resistivity ratios can reduce the effect of reservoir lithology and physical property variations on water saturation calculation. A power function describes the relationship between the radial resistivity ratio and reservoir water saturation. The bigger the radial resistivity ratio, the better the reservoir's oil bearing; the lower the radial resistivity ratio, the worse the reservoir's oil bearing; there is a one-to-one relationship between them. This approach is useful for evaluating low resistivity oil and high water layers [40].

Dahai Wang, Jinbu Li, et al., the triple-porosity model was established for determining the cementation exponent of triple-porosity media reservoirs by merging the Maxwell-Garnett theory and the series-parallel theory, which corresponded with genuine physical-experiment data of rocks.They developed a new model based on the link between total porosity and cementation exponent m of a triple-porosity medium composite system with various combinations of fractures and nonconnected vug porosity. The results showed that the fractures decreased the reservoir's cementation exponent while the vugs rose. Because of the mixture of matrix pores, fractures, and vugs, the cementation exponent of the triple-porosity media reservoir varied around 2.0. The cementation exponent proposed in the work could reasonably predict the cementation exponent of the strongly inhomogeneous triple-porosity media reservoir [41].

2.4. Permeability Determination methods

Typically, permeability data are obtained through routine analysis in the field or laboratory Core analysis is one of the most reliable techniques to determine permeability, with the disadvantages of high cost and time-consuming. An average value of permeability could be obtained by well testing, which gives information on the extension and connectivity of the reservoir. By applying the (MDT) technique, more accurate permeability data can also be achieved. The NMR log is now widely used to provide a fast estimation of the permeability profile along the wells. The most important methods developed to measure the permeability are:

Carman-Kozeny, developed an equation to evaluate permeability (k). The result of this calculation was a mixing between Darcy's and Poiseuille's laws. Where Darcy's law macroscopically quantifies fluid flow, Poiseuille's law explains the parabolic displacement of a viscous fluid in a straight-circular tube. The semi-analytical Carman-Kozeny (CK) equation does not correctly capture the permeability's dependence on porosity because (a) this equation has been derived for a solid medium with pipe conduits, rather than for a granular medium and (b) even if a grain size is used in this equation, it is not obvious that it does not vary with varying porosity [42, 43].

$$Dh = \frac{4\varepsilon V}{Sv} = \frac{4\varepsilon}{(1-\varepsilon)a_v} = \frac{\varepsilon d}{(1-\varepsilon)} \quad (14)$$

Where:

$$a_v = \frac{particle\ surface}{particle\ volume} \quad (15)$$

Wyllie and Rose, they proposed a modification of the Carman-Kozeny equation to calculate permeability from irreducible water saturation and formation resistivity factor (Fig. 6). Many assumptions about their equation are made. Firstly, there is no variance between minimum water saturation and irreducible water saturation. Secondly, this value of water saturation is a linear function of the grain surface. Finally, the same tortuosity of the porous media exerts an influence on the electrical conductivity as well as on the flow of the wetting phase fluid [44].

$$K = \frac{P\emptyset^Q}{Swi^R} \quad (16)$$

Where, Wyllie-Rose relationship is a generalized equation that requires the determination of values for the constants P, Q, and R to be calibrated from core measurements.

Tixier, the Tixier equation generated the experimental permeability equation by utilizing the Wyllie Rose equation. The outcomes of the Tixier equation were approximately similar to the permeability calculations from the Morris-Biggs gas equation [46].

Gary and Fatt, investigated the influence of stress on sandstone permeability, finding that not only rock permeability, but also permeability anisotropy in many sandstones, is a function of overburden pressure, and permeability reduction owing to stress effect is also a function of the radial to axial stress ratio [47].

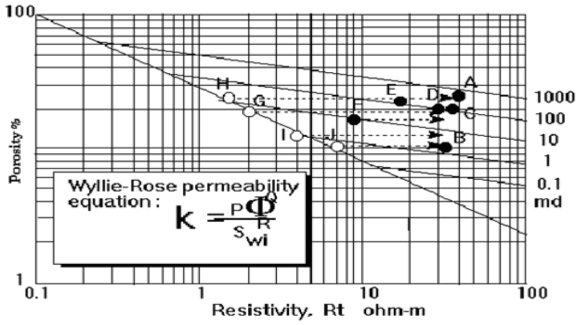

Fig. 6. Permeability Contours Drawn on Pickett Plot of Sandstone Data, Using a Wyllie-Rose Relationship with both Porosity and Irreducible Water Saturation [45]

Morris Biggs, using the Wyllie Rose equation, we provided permeability equations for both oil and gas reservoirs. The permeability obtained by Morris-Biggs in a completely gas saturated area (at irreducible water saturation) differs slightly from the permeability calculated by Timur. unlike the Timur model, presents the permeability equation for gas fields and does not require correlation utilizing irreducible water saturation and effective porosity of gas reservoirs [48].

$$K^{1/2} = C\frac{\emptyset^3}{Swi} \quad (17)$$

Where, C = constant, oil =250, gas =80.

Timur, suggested equation to estimate permeability by using in-situ measurements of residual water saturation and formation porosity. He tested several options in the laboratory by taking different measurements of permeability, porosity, as well as residual water saturation depending on 155 samples of sandstone that belonged to three oil fields. The main constraint of this equation is the fixed value of the cementation exponent (m), which is equal to 1.5 while this parameter may have other values in specific conditions [49].

Winland, the Winland hydraulic flow unit method was applied on core data and produced five groups to predicate permeability depending on pore throat size at mercury saturation of 35%. used the r35 parameter, along with other petrophysical, geological, and engineering data, to identify flow units in five carbonate reservoirs, r35 can be computed from permeability and porosity measurements on core samples [50].

$$\log r35 = 0.732 + 0.588\log k - 0.8641 log\emptyset \quad (18)$$

In Fig. 7, note that at a given porosity, permeability increases roughly as the square of the pore throat radius. And for a given throat size, the dependence of permeability on porosity is slightly less than Φ2. Hartmann and Coalson also They state that r35 is a function of both entry size and pore throat sorting and is a good measure of the largest connected pore throats in a rock with intergranular porosity [24].

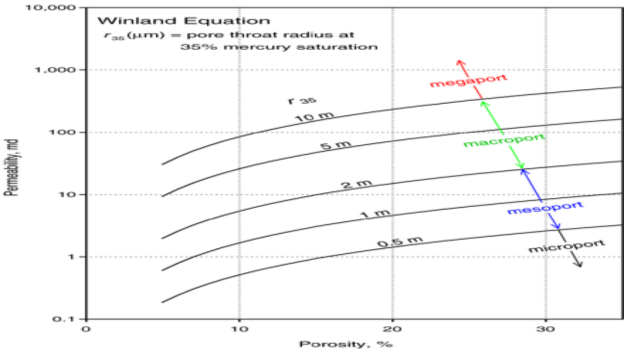

Fig. 7. Empirical Model Based on Regression Attributed to Winland [51]

Coates and Dumanoir, from irreducible water saturation and various types of effective porosity, an experimental relationship for the permeability estimates of average gravity oil reservoirs was presented[48, 52].

$$K^{1/2} = \frac{C}{W^4}\frac{\phi^{2W}}{\frac{Rw}{Rti}} \qquad (19)$$

Where:

C=23+465ρh-188ρh^2 and $W^2 = (3.75 - \emptyset) + \frac{1}{2}\left(\log_{10}\left(\frac{Rw}{Rti}\right) + 2.2\right)^2$

Bo Shen, et al., they devised a method for assessing permeability in glutenite reservoirs using well logs. This technique is based on the K-C model, the geometry equivalent parameter, and the flow porosity. Furthermore, the authors present a method for determining flowing porosity that can be employed by researchers interested in electrical current flow in pores. Although this method is more difficult than the usual permeability estimation method, it produces a consistent and accurate result for glutenite reservoirs with high variability [53].

2.5. Net pay evaluation method

Well net pay is an effective thickness that is important for determining flow units and objective intervals for well completions and stimulation programs. Thus, a section of the reservoir with high storability (driven by porosity), high transmissivity (driven by fluid mobility, which is defined as a ratio of permeability to fluid viscosity), and large hydrocarbon saturation is defined (driven by water saturation, Sw), The most important methods developed to measure net pay are:

McKenzie, the effective pore throat size was connected to show "producible and non-producible rock types." by the $\frac{K}{\emptyset}$ ratio (Fig. 8) [54].

Kolodzie, to associate the permeability and porosity with a pore throat radius (r) equal to varied mercury saturations, the Winland method was developed. He discovered that the 35th percent, or 35 percent of the pore volume ("R35," where he saw the inflexion on the mercury injection capillary curve vs. mercury saturation), had the best correlation with the Spindle Field data (it corresponds to a 0.5 m pore throat threshold value) [55].

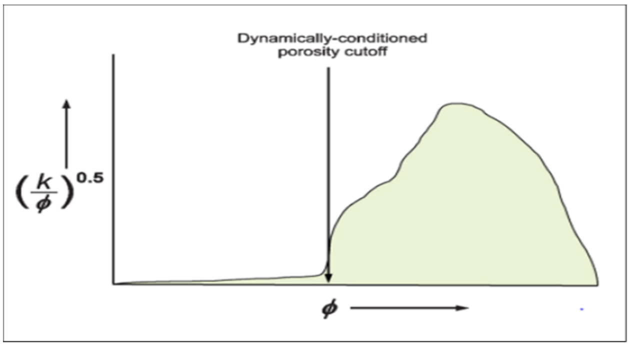

Fig. 8. Porosity Cut off [26]

Worthington and Cosentino, summarized that the cut-off values should be "dynamically conditioned" with a hydraulic parameter like pore throat radius, absolute permeability, or fluid mobility [56].

Jensen and Menke, the accuracy and mistakes in approximating multiple porosity cut-off values were investigated using a probabilistic approach. To calculate porosity cut-off values, they used a semilog porosity vs. permeability plot and the Y-on-X regression line. The regression line delivers the best results for estimating the net pay, while the RMA line gives the best results for NGR. [57].

Proposed Method, this method (Based on Diffusivity Equation) Diffusivity equation is designed to determine the pressure as a function of time and distance from the well for a radial flow regime of slightly compressible fluids.

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\emptyset \mu c}{0.000264k}\frac{\partial p}{\partial t} \qquad (20)$$

If a net pay zone has a greater flow rate in comparison to the other net pay zone, we can rank the first zone in a higher grade in comparison to the second one. Pressure is an important parameter causing fluid flow in hydrocarbon reservoirs as it can be inferred from Darcy's law. In the proposed method, division of flow rate by pressure difference is introduced as an index for net pay determination, after that, this index is calculated from diffusivity equation [8].

Lucia, demonstrated that by plotting interparticle porosity against permeability in carbonate reservoirs (Fig. 9), one could derive the type of rock fabric and detect pore-size classes. Additional pore types (vuggy, dissolution-enhanced) might modify these relationships. The permeability and porosity cut-off values should be defined based on these considerations. A unique permeability cut-off value based on engineering considerations (i.e. mainly depending on the fluid mobility) will lead to several porosity cut-off values depending on the rock fabric, i.e. the particle size [8, 58].

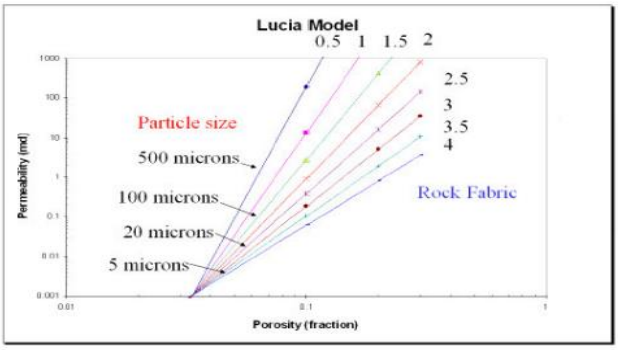

Fig. 9. Lucia Model for Porosity-Permeability Relationships Based on Rock Fabric [59]

Jensen and Menke, used a probabilistic approach to analyze the accuracy and errors in prediction of various porosity cut-off values. In the case where either determination of reservoir NGR and/or NP is obtained by cross-plotting surrogate quantities as Sw, Vsh, and/or φ, investigating the errors inherent to the regression methods giving log (k) vs. φ best fit lines is crucial since the misuse of regression methods may lead to additional errors. Such statistical issues related to the selection of porosity cut-offs based on regression lines [60].

3- Conclusion

The main scope of this paper is to provide a general review of the development of the field of formation evaluation and the available studies and applications to solve the problem. After reviewing a fair number of studies and papers on the formation evaluation studies the following were made:

1. The most popular and accurate method for determining shale volume is the gamma ray (single clay indicator method) to calculate shale volume. This method can be used for any formation that has shaly layers. The factor that effects clay volume calculating is The hole size, which refers to a large volume of drilling mud, has an impact on the gamma-ray record, and the reading can be influenced by environmental adjustment.
2. Using drilling data to achieve modified porosity and UCS values is beneficial in various formations. The modifications are not only applied in sandstone and shale formations, but the addition of gamma ray data permits such modifications to be possible for calculating porosity in formations of varied lithologies. They used drilling data in combination with the gamma ray (a better indicator) to determine porosity.
3. Water saturation factor can be computed using an intermediate parameter such as shale volume in sandstone reservoirs or directly anticipated from core data, well logs, or seismic characteristics. Well log data has been used to assess water saturation since 1942, when the Archie formula was introduced. To address the issue of needed water saturation approximation from core analysis in previous works, interpretation has recently used seismic data to directly calculate water saturation values or estimate proper rock physical properties such as shale volume, both of which are useful in the water saturation estimation process. These strategies make use of artificial intelligence computational agents to discover previously unknown non-linear correlations between seismic properties and the reservoir property of interest, which in this case is the water level.
4. There are two types of permeability approaches (non-experimental and experimental). Some theoretic methods are used in non-experimental methods to approximate the permeability, taking into account a fully saturated domain (Kozeny Carman), whereas laboratory methods combine three types of classifications: capillary effects (saturated and unsaturated), flow regime (constant pressure and constant flow), and flow direction (unidirectional and radial); then, the mathematical model of the method is established, taking into account such a combination.
5. The systematic use of ordinary least-squares regression for determining porosity cut-off values from permeability cut-off values may result in erroneous results and does not ensure good NP and NGR estimation. The regression line, as defined by Jensen and Menke, mathematically guesses the ideal porosity cut-off values by the use of another line, the Major Reduced Axis.

Nomenclature

(CEC) Cation Exchange Capacity
(Φt) Total Porosity
(ρg) Average Particle Density of Rock
(ρf) Effective Fluid Density in Flushed (Invaded) Zone
(ρmf) A Density of Mud Filtrate
(ρma) A Density of Matrix
(SEM) Scanning Electron Microscopes
(HI) Hydrogen Index
(UCS) Unconfined Compressive Strength
(ROP) Rate Of Penetration
(BVW) Bulk Volume Water
(MDT) Modular Dynamics Tester
(RQI) Reservoir Quality Index
(HFU) Hydraulic Flow Unit
(NP) Net Pay
(NGR) Net to Gross Ratio
(N) Water saturation exponent
(M) Cementation factor
(r35) The Pore Throat Radius at 35% Mercury Saturation
(K) Air Permeability
(Φ) Porosity In Percent Unit

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مراجعة لمراحل تطور الطرق المستخدمة لتقيم الخواص البتروفيزيائية

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الخلاصة

تحليل التكوينات الجوفية بدأ تطبيقه قبل اكثر من ٥٠ سنة في الابار النفطية المحفورة، ويشمل جميع طرق الحفر والتسجيل والاختبار وأخذ العينات بشكل عام. حيث يتم مناقش قيساسات الجس والنتائج المختبرية ذات الصلة بتقييم التكوينات تحت السطح، بما في ذلك إلقاء نظرة على عينات السوائل التي تم اخذها من هذه التكوينات من أجل تقييم التكوينات بدقة أكبر. لتعريف مصطلح "البتروفيزياء" مصطلح يستخدم للإشارة إلى فيزيائية أنواع معينة من الصخور، بينما تتعلق الجيوفيزياء بفيزيائية أنظمة الصخور الأكبر التي تتكون منها الأرض. علم البتروفيزيائية للصخور المكمنية هو العلم الذي يركز على دراسة الخصائص الكيميائية والفيزيائية للوسط المسامي والعناصر المكونة للصخور المسؤولة عن توزيع المسام والسوائل المكمنية. خلال السنوات الأخيرة، تم إجراء العديد من الدراسات حول خصائص الصخور، مثل المسامية، والنفاذية، والضغط الشعري، والتشبع الهيدروكربوني، وخصائص السوائل، والمقاومة الكهربائية، والجهد الذاتي أو الطبيعي، والنشاط الإشعاعي لأنواع مختلفة من الصخور. تُستخدم هذه الخصائص وعلاقاتها لتقييم وجود أو عدم وجود كميات تجارية من الهيدروكربونات في التكوينات التي تم اختراقها أو تقع بالقرب منها. الغرض الرئيسي من هذا البحث هو مراجعة تاريخ تطور التقنيات الأكثر شيوعًا المستخدمة لحساب خصائص البتروفيزياء في المختبر والحقول بناءً على خبرة العلماء و الباحثين في هذا المجال.

الكلمات الدالة: الخواص البتروفيزيائية، هايدروكاربون، حجم السجيل، مكمن، تشبع مائي، مسامية، نفاذية، تقنيات نفطية، تفسير.