Petro-physical Analysis of Well Logs for Reservoir Evaluation: A Case Study of Beda Formation in the Subah Oil Field of Sirt basin, Libya

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Abstract

In this study, two vertical onshore wells in the Sabah Oil Field in the Sirte Basin of north Libya are presented with the results of log analysis. The target of this work is to comprehend the structural layout, the overall stratigraphy of the research region, and to look into the petrophysical properties of the Sabah Reservoir of Oil Field. Using the cut-off technique for net reservoir and net pay zones for each well, locate the Beda reservoir zones, obtain the net pay thickness, and use it to calculate the average porosity and Sw. This study relies on the qualitative way to identify the wettability situation in the Beda reservoir using curve shape and particle behavior in fluids by drawing the relationship between the relative permeability and water saturation (Sw) for each zone in the reservoir for two wells which can derive the value of the cross point and the value of relative water permeability at maximum water saturation and correspond the results with Craig's rules to build up model of two cases either water or oil wet .

KEY WORDS: connate water saturation , relative permeability, capillary pressure, and wettability.

INTRUDUCTION

One of the most effective and crucial tools for characterisation of reservoir rock is the petrophysical study of well logs. The petrophysical characteristics of a reservoir, such as its lithology, porosity, and water saturation-permeability relationship, , determine the productivity of wells in hydrocarbon-bearing reservoirs. Formation evaluation refers to the method used in this petrophysics concept to assess the features of subterranean formations using borehole measurements. In order to identify potential zones for hydrocarbon accumulation with depth and thickness of these zones and to define the interfaces of oil, gas, or water in portions of the Subah oil field, the proposed study intends to quantitatively analyze the petrophysical parameters and interpret the well log data.

According to petroleum detection and production in Libya, the thermally mature Sirte shale (late Cretaceous Campanian) contains the Sirte basin's source rocks, which have good potential for producing oil and gas. The typical TOC of Sirte Shale source rock in Sirt Basin ranges from 2 to 5% (and can occasionally surpass 10%), indicating good to exceptional prospective source rock. It mostly comprises type I, and type II organic matter that is generated from the land (Khaled, 2022).The reservoirs in Sirte oil basin are ranged in rock type and age from fractured Pre-Cambrian basement (Granite), clastic reservoirs in the Cambrian-Ordovician Gargaf sandstones, and Lower Cretaceous Nubian (Sarir) Sandstone to Paleocene Zelten and Beda Formations to early Eocene carbonates Facha member commonly in the form of bioherms (Thomas S).

The cementation factor (m), which is equal to 2, and the saturation exponent value (n) can be obtained from the special core analysis that is available and can be calculated using the relationship between the resistivity (Rt) and neutron-density porosity (N-D) of two wells (Yalda, 2023). The Pickett cross plot was also used to calculate the Formation Water Resistivity (Rw), which has a value of 0.08.m. The combination of porosity (N-D) that serves as a reliable source of porosity data was found using the neutron and density log.

Using Archie's equation and the parameters (m, n, and a) acquired using the Pickett cross-plot method, it is possible to determine the water saturation. In Archie's equation, the adjustment porosity values from (eq. 3) were also replaced. As shown in table 2, once we have the Sw values for each well, we must use equations 8 and 9 to calculate the average water saturation (Sw) and porosity for each well. These equations call for net pay thickness (Hi) for net reservoir and net pay zones (Daniel, 2022) in order to identify the producer oil zones and reduce the risk of interpretation.

The most helpful uses of capillary pressure are to interpret/calculate relative permeability, estimate pore size distribution, and anticipate the initial fluid saturations of the reservoir, free water level, water-oil contact, and rock quality. There are several ways to collect capillary pressure data; the presence research uses the porous plate method (oil-brine system), which depends on air-brine capillary pressure. The system's wettability is interpreted using the concept of wettability

(Abouzar, 2020), which is then compared to stock tank oil floods at reservoir conditions using Craig's rules (Table 4). The majority of the results, however, will correspond to two wells when using Craig's rules to illustrate two cases where either water or oil is wet of the three criteria.

THE LOCATION OF TARGET AREA

The Sabah oil field is located approximately 280 km south of the Mediterranean Sea. The Sabah field is located in the southwest of the Sirte basin, in concessions NC74F and NC131, on a NW to SE oriented local high within the Zella graben. It is part of a series of complex, right-lateral strike-slip and anticline structures. The Sirte Basin is a Mesozoic rift basin in the northern part of Libya, the Sirte arm comprises a horst and graben series deepening to the northeast, which contains several oil and gas fields. The current study deals with the Zallah trough is the westernmost graben that contains economic hydrocarbon (Fig. 1).

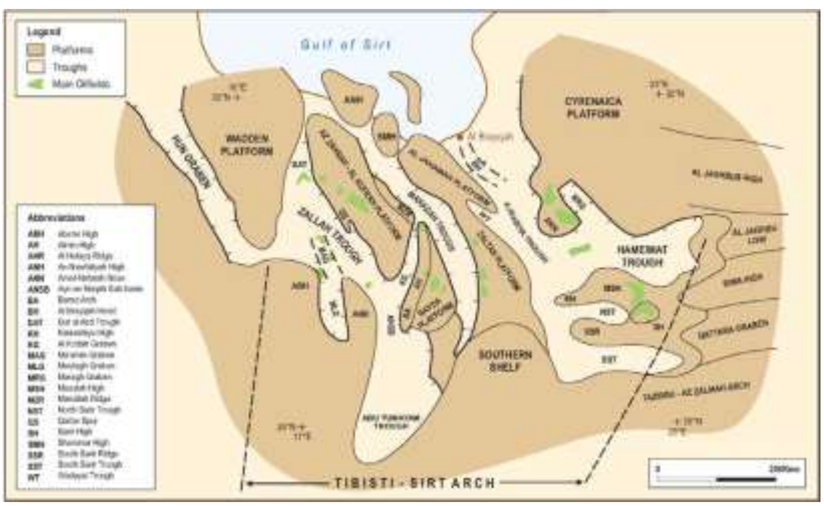


Figure 1: Location of Subah Oil Field in Zallah trough of

GEOLOGICAL SETTING OF SIRTE BASIN

The lithology from the surface down sand and shale to about 200 m thick, below this there is a mix of dolomite, limestone, and anhydrite to a depth of about 6400 m to 9100 m thick, the lithology is mixed shale and limestone overlying shale and sands (Fig. 2). It should be noted that the depths vary according to the relationship between faults and grabens.

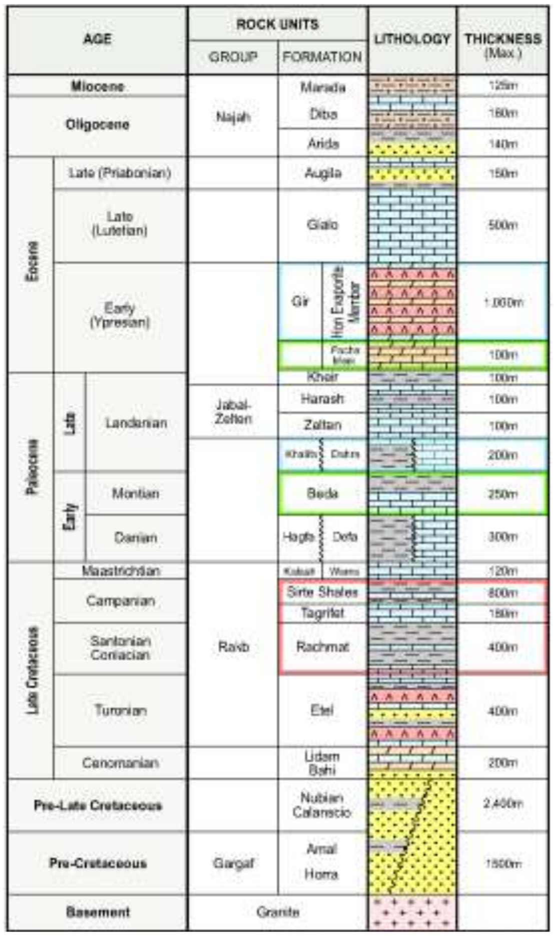


Figure 2: Generalized stratigraphic chart for the Sabah Oil

Following the opening of the Sirte Basin, sedimentary sequences varying from continental to near shore and marine sediments were deposited forming the stratigraphic sequences of the basin. It can be divided into four litho-stratigraphic sequences illustrated (Barr and Weggar, 1972). The first sequence at the basement is dominated by the Pre-Upper Cretaceous sedimentary cover that existed before the basin was found which includes Hofra, Gragaf quartzite, and Nubian sandstones. The second sequence is the Upper Cretaceous grab infill sediments deposited following the structural development of the grabens. The grabens were the accumulation sites of marine shale deposits and eroded from the structural high areas. The stratigraphic sequence deposited includes (in a secondary order) the Bahi, Adam, Etel, Rachmat, Rakab, and Kalash Formation. The third sequence is represented by the Tertiary sediments and is part of the garden-fill stage started by the early Paleocene deposits. The Paleocene and early Eocene rock deposits including the Hagfa Beda, Dahra, Zelten, and

Gir Formation are widespread and have good lateral Stratigraphic continuity. The fourth sequence starts near the beginning of the Lower Eocene. It is characterized by the slight to moderate local thickness variation within the Upper Gir Formation (Barr and Weggar, 1972).

Materials and Methods

The collection of subsurface information is not an easy matter, as it is considered one of the costly operations carried out by oil companies. One of the most important of these is the core operations and well logs that allow determining the type of lithology around the well and its diversity and physical properties, which allows the interpretation and clarification of these data and an understanding of their correct content of the subsurface to reduce the percentage of the risks with low cost (Ofwona, 2010). The most important steps that can be used in geophysical oil exploration are to define the types of geophysical open hole logging tools which are (a) compensated neutron (DSN), (b) spectral density (SDL), (c) natural gamma ray (NGRT), (d) caliper log, (e) spontaneous potential (SP) and (f) resistivity log (Ishwar, 2013). In addition to the data obtained from the core which helps in the analysis techniques provides the ability to measure the required petrophysical properties at reservoir conditions such as capillary pressure and relative permeability that cannot be addressed with other data sources as well as logging or seismic. As well as calibrating the data of the core and tying them to well log data of properly producing zones of each well to build up a model of each zone to identify the wettability phase for each well. However, by using the interpretation of the capillary pressure curve or by plotting correction water saturation versus subsea depth to identify the oil-water contact for each well and using the specific depth of (OWC) to get the thickness of the transition zone as well as the free water level (FWL).

Data Collection And Analysis

In most petrophysical studies, some well logs or formation parameters are used to help evaluate the reservoir. In the present study, well logs provide of the present study are Gamma-ray, Resistivity, Neutron, Density and Sonic logs which are used in evaluating Petrophysical properties such as Porosity (θ), Hydrocarbon saturation (So), Water Saturation (Sw) and Water Resistivity (Rw) to infer the hydrocarbon-rich formation of the target area (Ishwar, 2013). With the knowledge of the hydrocarbon-rich formation, we will use a technique known as a cut-off technique that helps in reducing the intervals that do not contain hydrocarbons in the formation, so it is possible to determine the net pay thickness of the reservoir by using some equations and hence in estimating the average of both porosity(θ) and water saturation (Sw). However, it is also possible to link this information obtained from each zone with the information obtained from core analysis to know the distribution of fluids in the reservoir in determining the free water zone (FWL), transition, and oil zone by using the relationship between water saturation (Sw) and capillary pressure (Pc) to identify the irreducible water saturation(Swi) or connate water saturation (Swc) of each zone and compare it with which that we get from well calculation (Morrow and Melrose, 1991).

Archie's Equation and Correction of Parameters

There are many types of reservoir rocks in some kinds of sedimentary rocks, for example, carbonate rocks that are considered of great economic importance because more than 70% of the oil reserves in the world are found in this type of rock and their classification depends on lithology, texture, and structure. The equation combining two parts resistivity index (IR) and Formation Resistivity Factor (FR) to calculate water saturation (Archie, 1942) (eq. 1). The Archie equation depends on determining the water saturation in the homogeneous formation reservoir only. The determination of water saturation in a heterogeneous reservoir is becoming more challenging, as Archie's equation is only suitable for clean homogeneous formation (Yalda, 2023) and Archie's parameters are highly dependent on the properties of the rock and Archie's parameters (m, n, and a) depend to a large extent on the rock properties. This method depends on linking the hydrocarbon saturation with resistivity in clay-free rocks. This study is based on the Beda formation, which consists of mainly of various interbedded limestone lithofacies with subordinate dolomite and calcareous shale. The main rock types include argillaceous calculative and skeletal and oolitic calcarenites. This study relied on the values obtained from the method of the core archie parameter estimation (CAPE) or three-dimensions (3D) in determining the parameters of Archie in heterogeneous and homogeneous reservoirs because of unrealistic assumptions involved in the conventional method.

$$Sw = \left(\frac{a}{\emptyset^m} * \frac{Rw}{Rt}\right)^{1/n} \qquad \text{(eq.1)}$$

The ability to interpret different criteria from data obtained from wells will assist in determining the reservoir zone. The analysis of two wells in this study has been completed. To illustrate the application of logging techniques and to establish the hydrocarbon potential in one block of Sirte Basin. In the presence study, a complete package of porosity and resistivity logs, records including neutron, density, sonic, and induction Logs, have been recorded across the Beda Reservoir. The thickness interval of each log was read every two feet to get accurate information about the reservoir in terms of volume of shale, porosity, water saturation, net pay thickness (zonation), and hydrocarbon pore volume. However, The cementation factor (m) can be obtained from the special core analysis, available, and it can be determined by using the relationship between resistivity (Rt) and neutron-density porosity (ØN-D) of 2 wells by using the Pickett cross-plot technique of obtaining cementation factor which is equal 2 as well as Saturation exponent value (n) (Pickett G.R.1973) (Fig. 3). The Formation Water Resistivity (Rw) was determined by using the Pickett cross plot as well and has value equal to 0.08 Ω.m (Fig. 3).

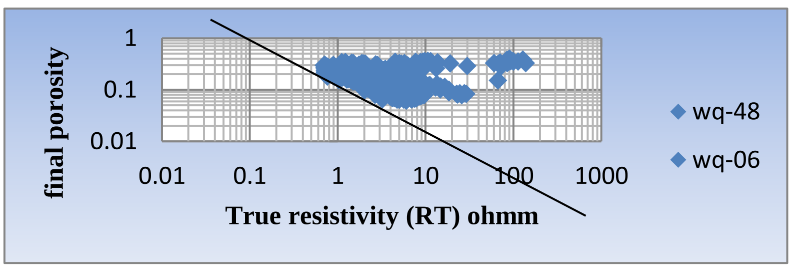


Figure 3: Illustrate Picket cross Plot (Plot of Resistivity vs Porosity) of three wells in Beda reservoir.

The Porosity Estimation and Correction

The neutron, and density log were used to determine the combination porosity (ØN-D) that provides a good source of porosity data. The density porosity can be determined by using (eq. 2) ,while the neutron porosity can obtain it by reading the value directly from the log based on the rock type of the Beda reservoir. However, after we get the porosity values of density and neutron, it is possible to get the combination porosity with better estimates of porosity than using either tool separately by using (eq.3).

$$\emptyset D = (\rho ma - \rho b) / (\rho b - \rho f) \quad \text{(eq. 2)}$$

$$\emptyset c = \frac{\sqrt{\emptyset n^2 - \emptyset d^2}}{2} \quad \text{(eq. 3)}$$

The porosity values by the previous equations see Table 1, we need to correct the values of porosity to get good results to compensate for these values of porosity for two wells in the Archie equation. Thus, As a first step, we will work on calculating the volume of shale in the pours of the Beda reservoir and the volume of shale expressed in decimal fractions or percentages is called Vsh, which can be calculated By Larionov (1969) equation as shown in (eq. 4), that requires us to find the value of the gamma-ray index (IGr) by (eq. 5) as the first step needed to determine the volume of shale from gamma-ray log.

$$V_{sh} = 0.083\,(2^{3.7IGR} - 1) \qquad \text{(eq. 4)}$$

$$I_{Gr} = GR_{log} - GR_{min} / GR_{max} - GR_{min} \qquad \text{(eq. 5)}$$

Obtaining the correct porosities from density–neutron logs when the two logs record different porosities for a zone, can be done by (eq. 6), and (eq. 7), As both equations need to know the values of Vsh and GRmax for neutron and density porosity of each well. To reduce the risks resulting from the interpretation and obtain good values of water saturation in the reservoir by replacing the corrected values in the Archie equation. However, the values obtained from (eq. 6), and (eq. 7) can compensate them in (eq. 3) to get the correction of combination porosity as shown in table 1.

$$\emptyset N_{Crr} = (\emptyset N - (\emptyset N\ GR_{max} * 0.3 * (\ Vsh / 0.45))) \qquad \text{(eq. 6)}$$

$$\emptyset D_{Crr} = (\emptyset D - (\emptyset D\ GR_{max} * 0.3 * (\ Vsh / 0.45))) \qquad \text{(eq. 7)}$$

Table 1: The values of the correction of combination porosity for two wells of Beda reservoir

well name	zone	top	base	ØN	ØD	ØN-D	ØNcrr	ØDcrr	ØN-Dcrr	Vsh
wq-6	AC-1	5408	5436	19-41%	17-36%	26-37%	28-43%	16-36%	26-39%	3-40%
	AC-2	5464	5470	21-30%	35-36%	34-36%	33-35%	33-36%	33-35%	16-45%
	AC-3	5566	5578	5-9%	10-14%	8-13%	5%-10%	9-14%	8-12%	5-20%
wq-48	G-12	5582	5614	15-40%	29-33%	16-30%	1-25%	26-34%	10-34%	12-45%
	G-15	5630	5648	12-35%	14-27%	9-17%	2-19%	15-22%	10-22%	9-45%

The Determination Of Water Saturation (Sw)

The water saturation can be calculated by using Archie's equation (eq.1) with parameters (m, n, and a)obtained from the Pickett cross-plot technique (Fig. 3) of two wells. As well as the values of correction porosity obtained from (eq. 3) and substituted them in Archie's equation. Now, after getting the values of Sw for each well, we need to find the average of water saturation (Sw), and porosity for each well by using (eq. 8), and (eq. 9) that require net pay thickness (Hi) for net reservoir and net pay zones to identify the producer oil zones to minimize the risk of interpretation as shown in table 2.

$$S_w\ (avg) = \sum (Øi \times Swi \times Hi) / \sum (Øi \times Hi) \qquad \text{(eq. 8)}$$

$$Ø\ (avg) = \sum (Øi \times Hi) / \sum (Hi) \qquad \text{(eq. 9)}$$

Table 2: The values of the net reservoir and net pay zones for two wells

well	net reservoir					net pay zones				
	∑Hi	∑ Hi*ɸ	∑ Hi*ɸ*Sw	average ɸ	average Sw	∑Hi	∑Hi*ɸ	∑ Hi*ɸ*Sw	average ɸ	average Sw
wq-6	42ft	12	4	29%	33%	37ft	14	3	38%	21%
wq-48	50ft	18	5	36%	28%	42ft	11	2	26%	18%

The Net Pay Thickness Techniques (Hi)

The Net pay thickness of the reservoir represents intervals having porosity greater than or equal to the cutoff porosity of (10%) and having water saturation less than the cutoff water saturation of (50%) and volume of shale less than the cutoff condition of (40%) as shown in table 2, all these values will be standard of two wells **(**Crain, 1986). However, by using techniques of cutoff condition which will help to identify the producer oil zone or non-oil zones for each well to get the average of water saturation and porosity and compare them with net reservoir results. Moreover, the average values of water saturation and porosity will help to estimate the reservoir.

Table 3: illustrate the values of the cut-off selection of each zone for two wells

well	zone selection			cut-off selection		
	zone	top	base	Vsh (≤40%)	θ (≥10%)	Sw (<50%)
wq- 6	AC-1	5408	5436	3 - 28 %	15 - 35 %	6 - 18 %

	AC-2	5464	5470	16 - 32 %	34 - 35 %	23 - 27 %
	AC-3	5566	5578	8 -32 %	29 - 40 %	24 -50 %
wq- 48	G-12	5582	5614	12 - 40 %	17 - 34 %	9 - 34 %
	G-15	5630	5648	9 -36 %	10 - 22 %	20 - 50 %

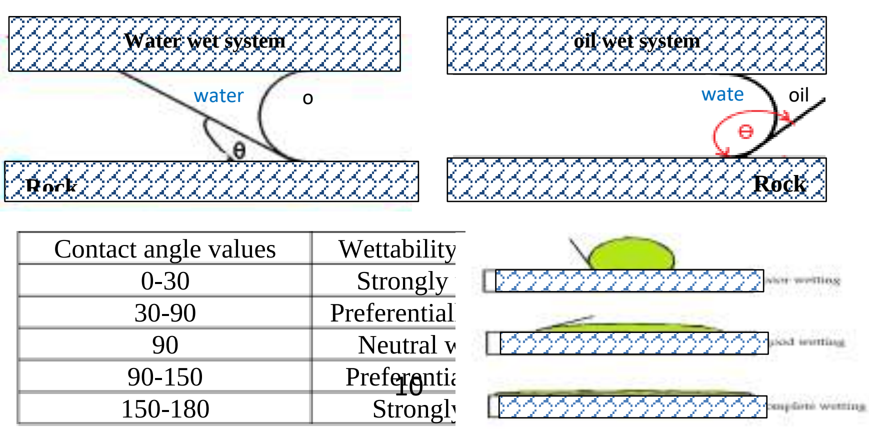
Irreducible or Connate Water Saturation and Relative Permeability of Beda Reservoir

The hydrocarbon identification zones in Beda reservoir have been done by the previously used means, which enabled the conclusion of hydrocarbon zones with water saturation (Sw) above the connate water saturation (Swc), some water along with the hydrocarbon is likely to occur in the transition zone between oil and water. Understanding the relationship between water saturation (Sw) and (Swc) connate water saturation with relative permeability of water or hydrocarbons to identify the water cut. Hence, it is possible to move on toward the concepts that can be described by the capillary pressure curves and relative permeability curves.

The capillary pressure results from the difference between two fluid forces and their bounding solids. One acts as cohesive (liquid-liquid) forces (interfacial tension) and the other as adhesive (liquid-solid) forces (wettability) (Abouzar, 2020). Wettability is the ability of one fluid to spread or to adhere to surface in the presence of other immiscible fluids. Thus, the wetting phase depends upon increasing the adhesive more than the cohesive, while the non-wetting phase depends upon exceeding the cohesive forces more than the other. However, the contact angle can demonstrate the relative wettability of fluid, which is the angle between the two fluids and rock interface as measured through the denser fluids (Fig. 4) and capillary pressure can be calculated by (eq. 10), and (eq. 11)

$$P_c = (\rho w - \rho nw)\ gh \qquad \text{(eq.10)}$$

$$P_c = \frac{2\sigma \cos\theta}{a} * c \qquad \text{(eq. 11)}$$



Contact angle values	Wettability
0-30	Strongly
30-90	Preferential
90	Neutral v
90-150	Preferentia
150-180	Strongl

Figure 4: Illustrate the angle between the two fluids and rock interface

The most useful purpose of capillary pressure is to predict the initial fluid saturations of the reservoir, free water level, water oil contact, and rock quality, assist in the interpretation/ calculation of relative permeability, and calculate pore size distribution. There are many methods of obtaining capillary pressure data, the presence study depends on air-brine capillary pressure by the porous plate method (oil-brine system). However, the distribution of fluid in a homogenous reservoir can be illustrated in (Fig. 5) and most of all the results that have got from the wells in the reservoir will draw figures and calibrate them to the relative permeability of each zone of wells in the reservoir to build up a model to final picture that can illustrate the distribution of fluid in reservoir.

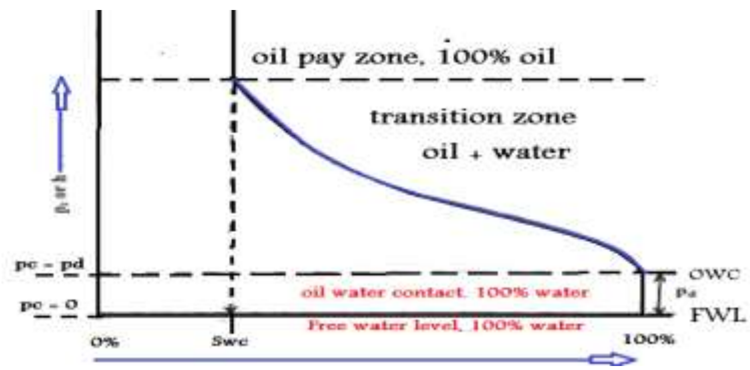


Figure 5: shows the typical curve of fluid distribution in homogenous reservoir

Moreover, the free water level (FWL) and water oil contact (OWC) can be calculated by using (eq. 12) and (eq. 13) as well the height above the free water level (h) from (eq. 14) but before that we need to convert the Pc lab to a Pc reservoir and that can be done by (eq. 15) to obtain good results. However, capillary pressure lab data obtained from a small core sample which needs to upscale the data to represent a particular reservoir by using the Leverett J-Function from capillary pressure can be calculated using the following equation (eq. 16) that can serve quite well for the same formation (with specific lithology) having different porosity and permeability.

$$FWL = OWC + (144\ P_d / \Delta\rho) \qquad \text{(eq. 12)}$$

$$OWC = FWL - (144\ P_d / \Delta\rho) \qquad \text{(eq. 13)}$$

$$H = 144\ P_c / \Delta\rho \qquad \text{(eq. 14)}$$

$$(P_c)_{res} = (P_c)_{lab} \left(\frac{\sigma\ res}{\sigma\ lab}\right) \left(\sqrt{\emptyset res\ kcore} * \sqrt{\emptyset core\ kres}\right) \qquad \text{(eq. 15)}$$

$$J_{sw} = \left(P_{cr} / \sigma \cos\theta \right) * \sqrt{\frac{k}{\emptyset}} \qquad \text{(eq. 16)}$$

Relative permeability relates absolute permeability to fluid effective permeability when a particular occupies just of the total pore space (eq. 17). However, the relative permeabilities are an increasing function of the fluid saturation and affect pore geometry, fluid distribution, and wettability. Whereas the relative permeabilities vary depending on rock wettability and the way saturation changes (drainage/ imbibition) (Abouzar, 2020). The interpretation of wettability is used to interpret the wettability of the system and the comparison with stock tank oil floods at reservoir conditions according to Craig's rules (table 4), whereas the most of result will correspond to two wells with Craig's rules to illustrate of two cases either water or oil wet of three criteria.

$$K_{ro} = \frac{Ko}{k} \qquad K_{rw} = \frac{Kw}{k} \qquad K_{rg} = \frac{Kg}{k} \qquad \text{(eq.17)}$$

Table 4: illustrate three criterion of two cases of wettability according to Craig's rules

Criterion	Water-wet	Oil-wet
Connate water saturation (Swc)	Usually ≥ 20-25 %pv	Generally < 15% pv
Cross point of Kr curves	≥ 50% water saturation	< 50% water saturation
Krw @ max Sw	Generally < 0.3	0.5 may be up to 1

The typical oil-water relative permeability curve (Fig. 6) illustrates the two phases' flow region in which except for endpoints, the sum of relative permeabilities is always strictly than one and those curves indicate the flow of oil and water in the reservoir and corresponding the results of presence study to typical curve to build up the model of each well. However, as Sw increases, Kro decreases, and Krw increases until reaching residual oil saturation (Sor).

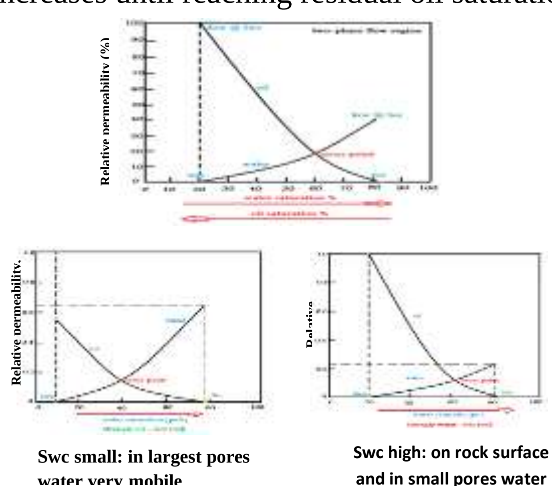


Figure 6: illustrate the typical oil-water relative permeability curves and the impact of wettability

Results and Discussion

Evaluation and identification of the Beda reservoir zone is based on making use of available data in interpreting various parameters of two wells. However, the values of cementation factor (m) and formation water resistivity (Rw) have been identified by the Pickett cross-plot technique. It was constructed by plotting porosity (ØN-D) values versus deep resistivity (RILD) values of 2 wells on log-log paper. A line of wet resistivity @ 100% Sw was drawn through the most southwest data points as shown in (Fig. 3). Furthermore, the bottom hole temperature (BHT) of 75OF was plotted on the pore water resistivity chart to get the formation water resistivity (Rw) which is equal to 0.08 ohmm which is the same value found on the Pickett cross-plot. Also the saturation exponent “n” was kept at “1” from the special core while the cementation factor “m” was varied from 1.90 up to 2.01 for the Pickett plot. Not only the saturation parameters be obtained from the Pickett cross-plot technique but also can be obtained from special core analysis, available. However, the results were obtained by compensating values of saturation parameters in Archie’s equation to obtain the Sw values for each well. Therefore, the initial values of Sw were not satisfied and thus corrected the porosity for each well by using the equations (eq.6), (eq.7) and (eq.3). a cut-off technique was used to obtain the net pay thickness for each well so that it is easy for us to determine the zones of each well. Therefore, the results show that well (wq-06) contains three zones. The zone (AC-1) has varied porosity from 26% up to 39%, zone (AC-2) from 33% up to 35%, zone (AC-3) from 8% up to 12% while the well (wq-48) contains two zones. The zone (G-12) its porosity from 10% -34% while the zone (G-15) has porosity from 15% - 22% as shown in table 1.

Identifying the zones of Beda reservoir by using the cut-off technique as shown in Table 3 for net reservoir and net pay zones for each well to get the net pay thickness and use it to determine the average of porosity and Sw by using (eq.8) and (eq.9). However, the results show that the average porosity of well (wq-06) is 38% and average the water saturation (Sw) is 21% while the well (wq-48) its porosity is 26% and average water saturation (Sw) is 18% as shown in table 2.

There are many methods to evaluate rock wettability which are differentiated into two methods known as quantitative and qualitative methods. This research depends on the qualitative method in determining the wettability case in the Beda reservoir based on the shape of curves and the behavior of particles in fluids. The most common method to get rock wettability is drawing the relationship between the relative permeability and water saturation (Sw) for each zone in the reservoir for two wells which can derive the value of the cross point and the value of relative water permeability at maximum water saturation as well as the relationship between capillary pressure (Pc) and water saturation (Sw) which can derive the value of connate water saturation. However, both relationships tie in with water saturation (Sw) which can help to draw a model of two figures and correspond the results with Craig's rules to illustrate two cases of either water or oil wet of three criteria. Moreover, the results of calibrating capillary pressure to relative permeability for each zone of two wells.

The result of values of capillary pressure(pc) versus water saturation (Sw) curve and relative permeability versus water saturation curve is show in Table 5 below. However, the zone (AC-1) in well (WQ-06) shown in figure (8) illustrates the value of connate water saturation (Swc) which is 12% compare with the value of cross point 53% and the relative permeability value (Krw) at maximum water saturation is 0.48md and compare these values with Craig's rules that leading to a case of oil-wet.

Table 5: illustrate the three criterion of two cases of wettability of two wells of Beda reservoir.

well	zone	lithology	average ø	average Sw	Swc	cross point	Krw @ max Sw	Remarks
wq- 6	AC-1	medium calcirudite : miliolid packstone	38%	21%	12%	53%	0.48	Oil wet
	AC-2	medium calcarenite: peloid wackestone			25%	45%	0.49	Oil wet
	AC-3	medium calcarenite: formaminiferal wackestone			52%	73%	0.40	Water wet
wq- 48	G-12	argillaceous calcilutite	26%	18%	9%	29%	0.53	Oil wet
	G-15	dolomite and calcareous shale			42%	62%	0.42	water wet

Figure 9 shows of the (AC-2) zone, is a case of oil-wet even though the values of connate water saturation is more than 15% but the cross point is less than 50% while Figure (10) of the (AC-3) zone achieves the conditions of three criteria to the case of water wet. Moreover, the value of relative permeability of water (Krw) at maximum water saturation (Sw) in well (wq- 6) is highest in the zone (AC-1) (0.48 md) and zone (AC-2) (0.49 md) which means oil zone and lowest in the zone (AC-3) (0.40md) which means water wet.

The well (wq-48) has two zones and each zone has perfect results compared with Craig's rules. Figure 11 represent of the (G-12) zone of the well (wq-48) illustrates the case of oil-wet and its values match with Craig's rules with good results for the oil-wet case, while Figure 12 of the (G-12) zone shows the perfect values in case of water wet compare it with Craig's rules. Moreover, the value of relative permeability of water (Krw) at maximum water saturation (Sw) in the well (wq- 48) is highest in the zone (G-12) (0.53md) which means oil zone and lowest in the zone (G-15) (0.42md) which means water wet.

The Oil water contact (OWC) is determined by plotting water saturation (Sw) values versus subsea depths of two wells as shown in Fig (7) which indicates that the oil-water contact of the Beda reservoir is defined at the well (wq-48) in the subsea depth of - 5220 ft and at well (wq-06) in the depth of -5520 ft and this difference is likely to be due to some geological structure. However, the value of (OWC) can be helpful to determine the free water level by using (eq. 12) at which well with specific thickness as well as the height above the free water level (h) from (eq. 14) which is very important to determine the thickness of the transitional zone of each well.

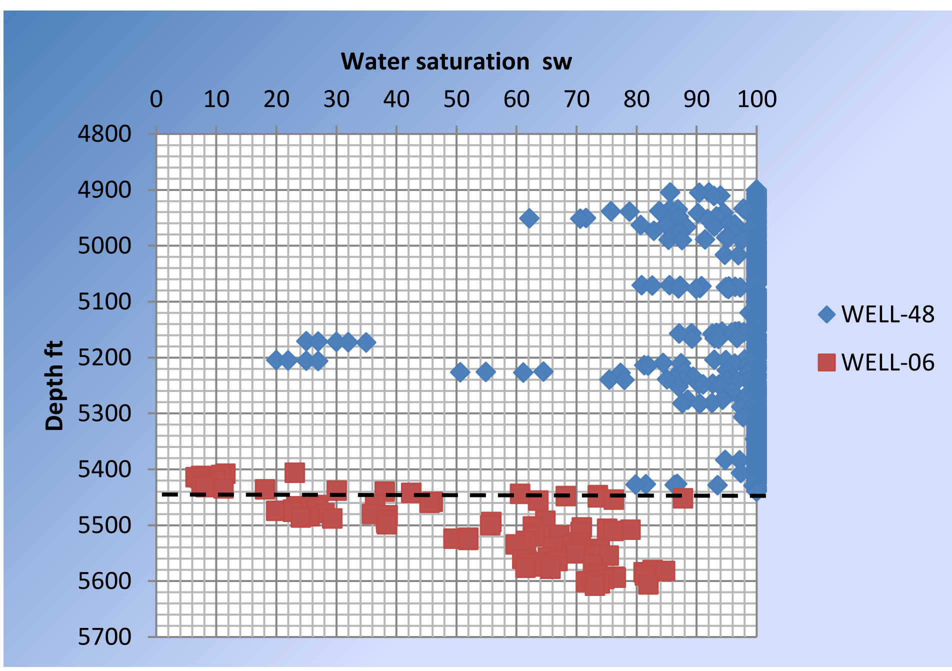


Figure 7: illustrates the Plotting OF Water Saturation Values Versus Subsea Depth of two well to determine the (OWC)

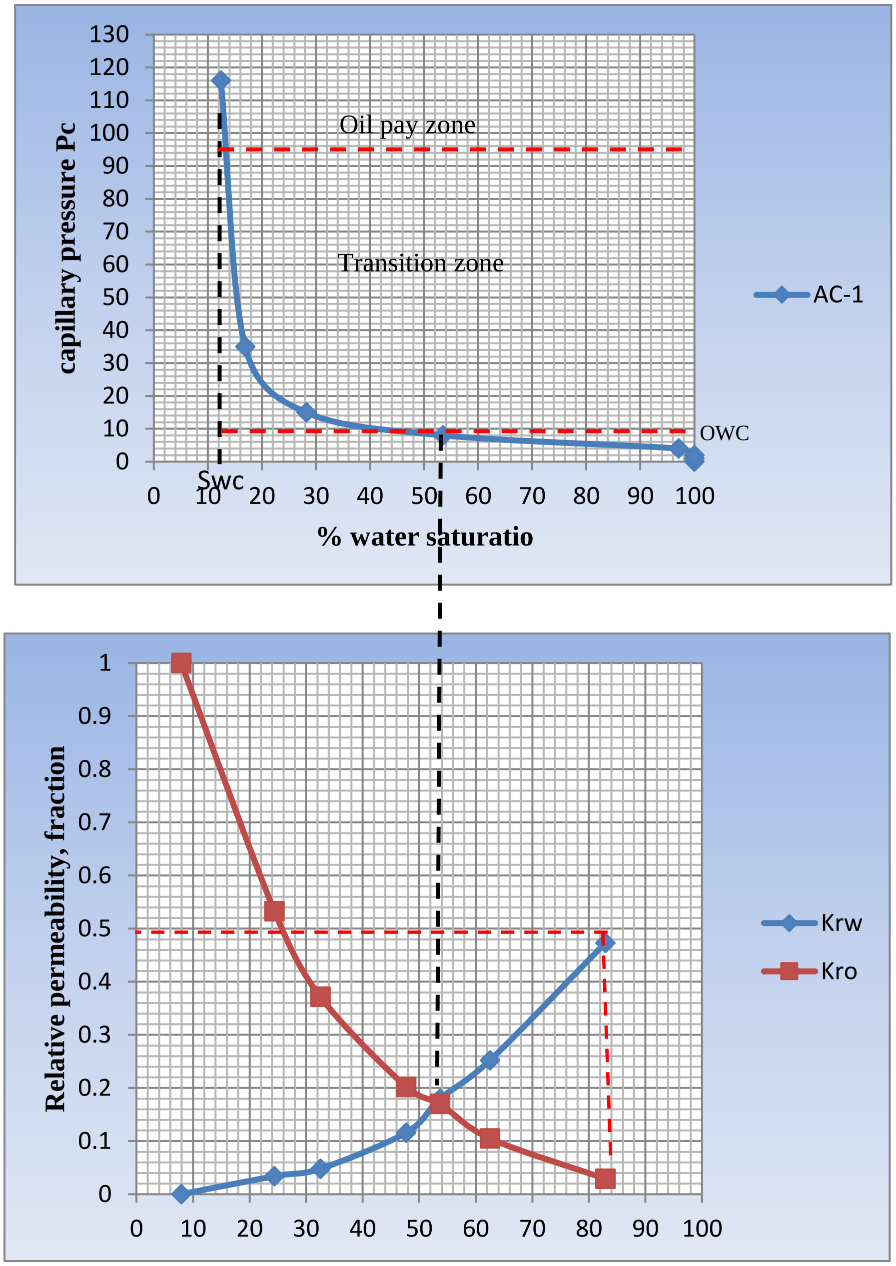


Figure 8: Illustrates the relationship of capillary pressure (Pc) and relative permeability versus water saturation model of (AC-1) zone in well (WQ-6)

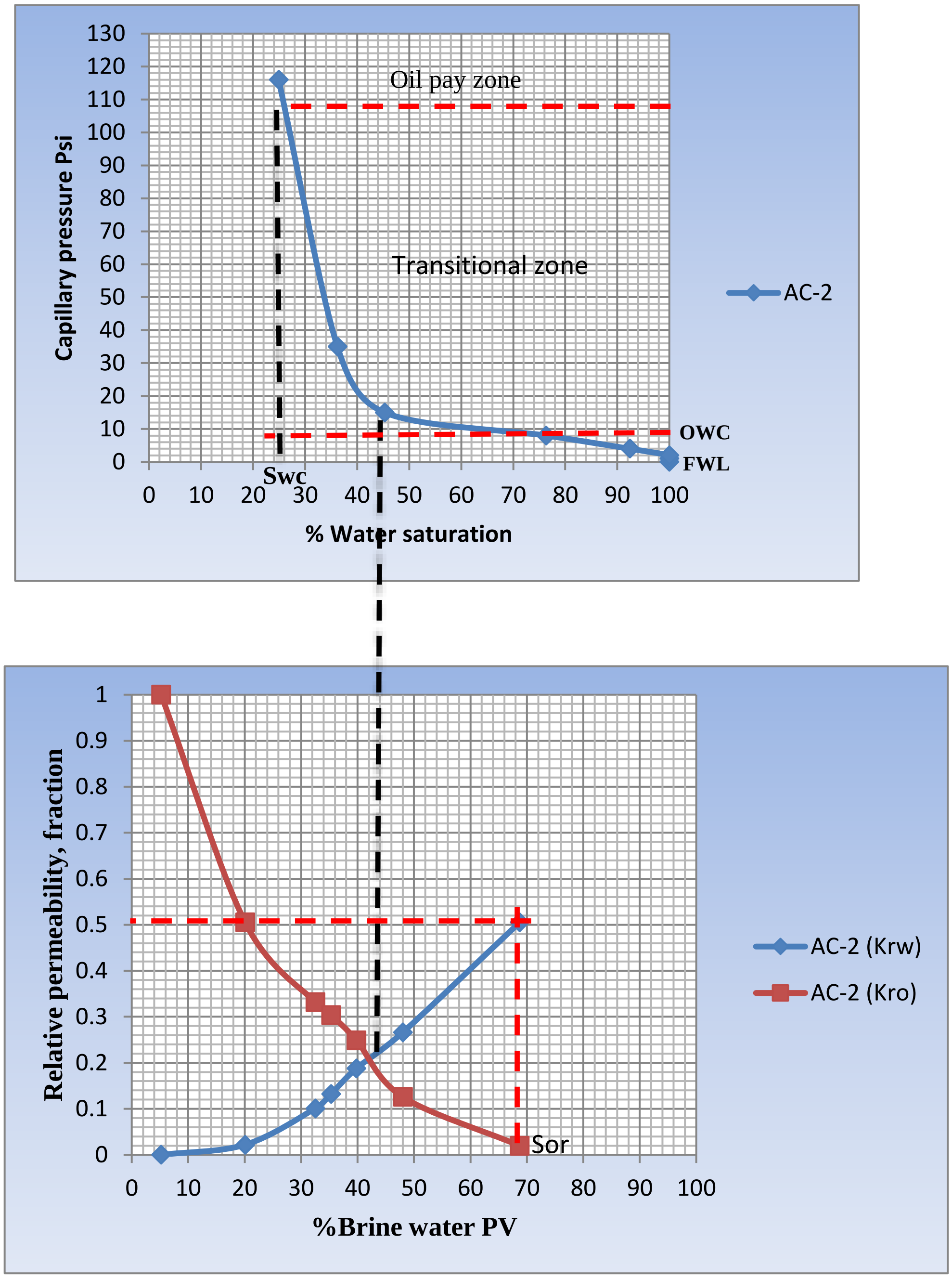
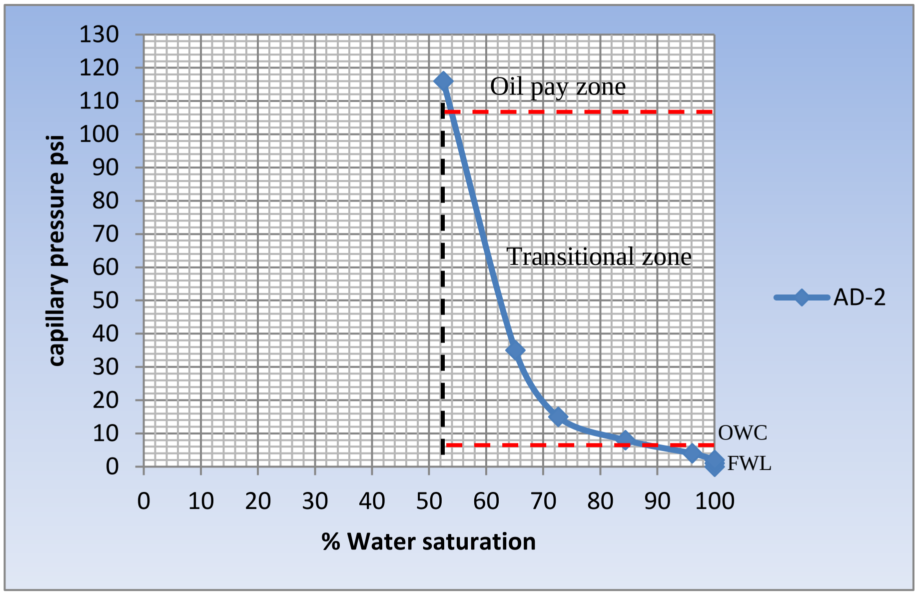


Figure 9: illustrates the relationship of capillary pressure (Pc) and relative permeability versus water saturation model of (AC-2) zone in well (WQ-6)



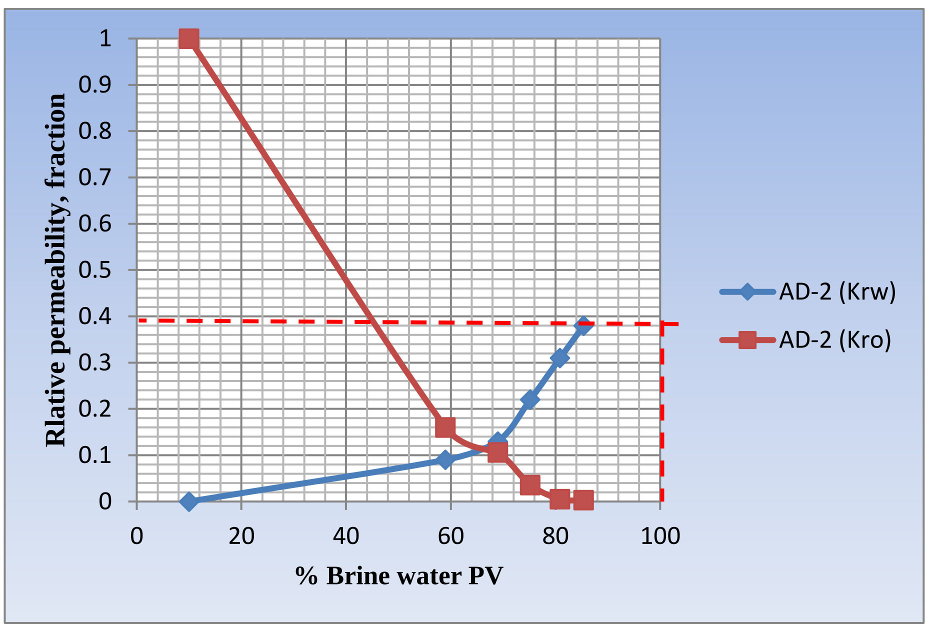


Figure 10: illustrates the relationship of capillary pressure (Pc) and relative permeability versus water saturation model of (AC-3) zone in well (WQ-6)

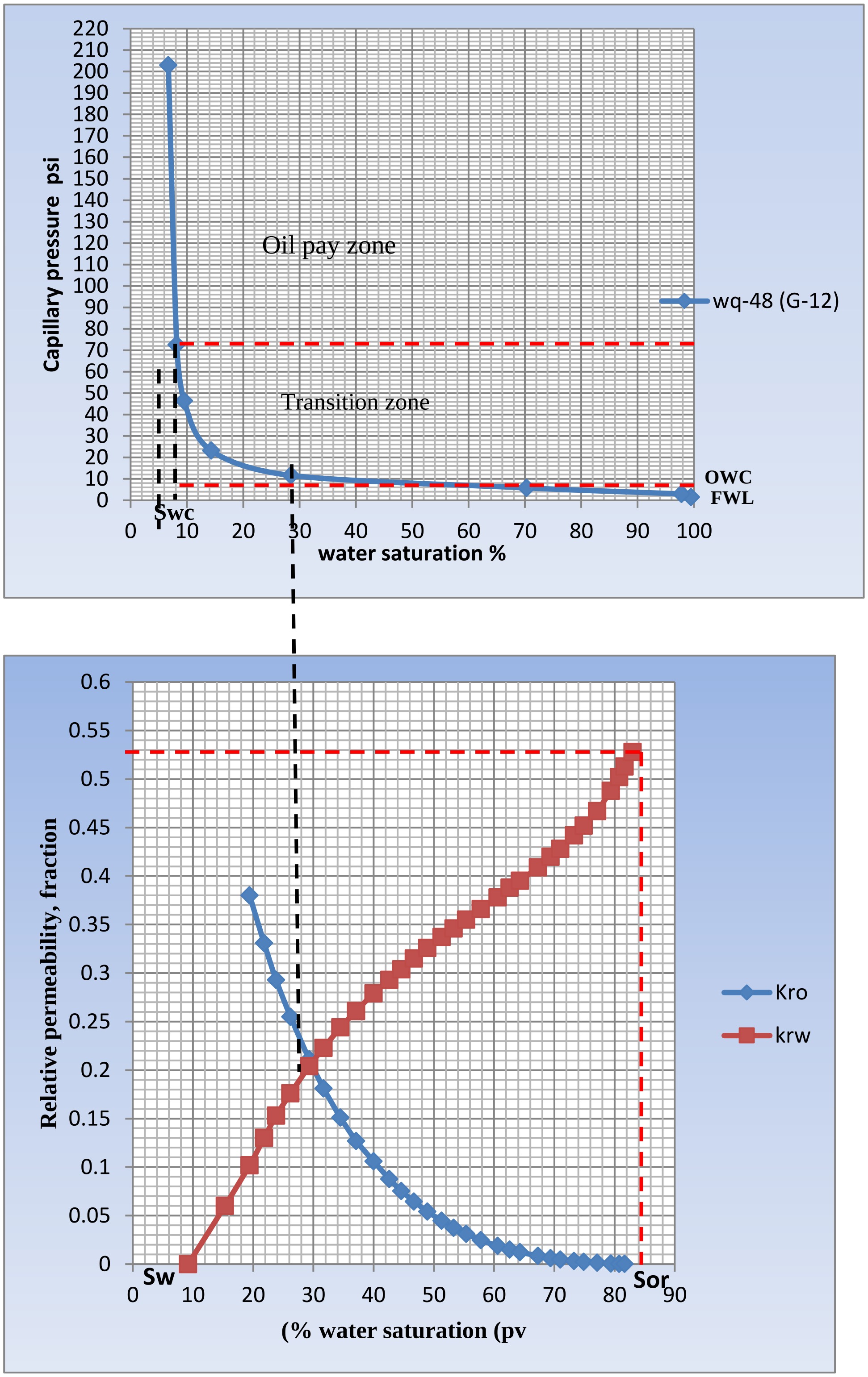


Figure 11: illustrates the relationship of capillary pressure (Pc) and relative permeability versus water saturation model of (G-12) zone in well (WQ-48).

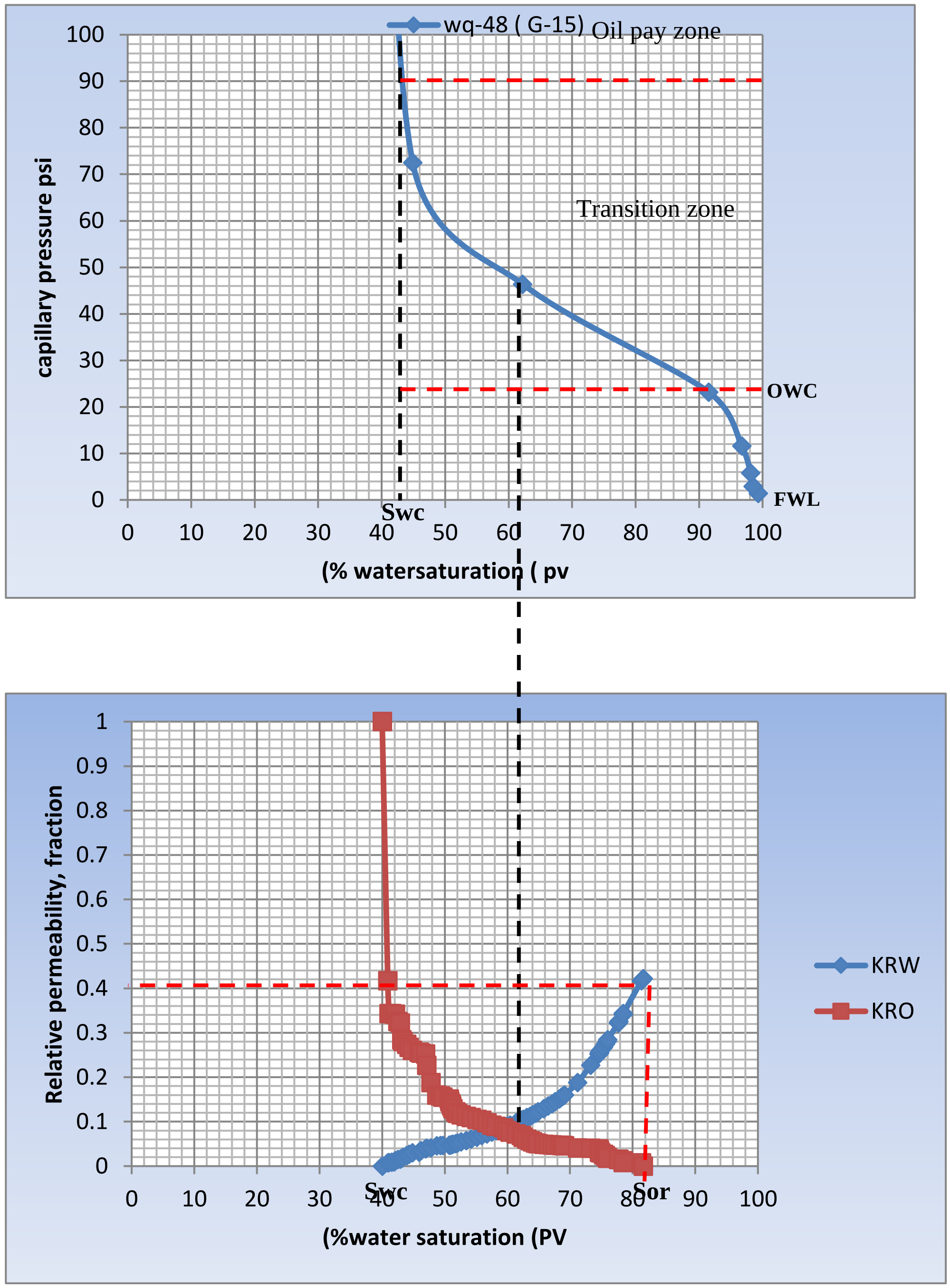


Figure 12: illustrates the relationship of capillary pressure (Pc) and relative permeability versus water saturation model of (G-15) zone in well (WQ-48)

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