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Chapter One: Introduction

1.1 General Introduction

In petroleum exploration production and development, formation evaluation is used to determine the ability of a borehole to produce petroleum essentially it is the process of recognizing a commercial well when a well is drilled.

Development plan for any reservoir depends on the assessment of the hydrocarbon in-place, which depends mostly on formation evaluation. The most common petro physical exercises used in evaluating reservoir and assessing reserves are log analysis, core measurement and wire line formation testing.

Formation Evaluation (FE) is the process of interpreting a combination of measurements taken inside a wellbore to detect and quantify oil and gas reserves in the rock adjacent to the well. the objective of FE can be used to describe the process that determine the availability of formation to produce oil and other petroleum product ,and interpreting a combination of measurement taken inside a well bore to detect and quantify oil and gas reserve in the rock adjacent to the well.

In this research two types of data have been used: special core analysis (SCAL) & wire line formation tester (WFT) data.

Core analysis is the name given to the test procedures and data collected on core samples.

Special core analysis (SCAL) gives information about the rock wettability, the distribution of oil, gas and water in the reservoir (capillary pressure data), residual oil saturation and multiphase flow characteristics (such as capillary pressure and relative permeability). Measurements of electrical and acoustic properties, which are mainly used in the interpretation of well logs, are occasionally included in special core analysis.

assumptions, this pressure is identical to the pressure of formation fluid, implying that the wireline tester measurement is unaffected by invasion process. Recent work has shown that many formation tester surveys cannot be explained if these assumptions were true. In reality, the concepts of free fluid level, fluid contacts, rock wettability, and pore fluid

pressures are so intimately related that the measured tester pressure cannot be simply identical to formation pressure. The objectives of WFT are to determine the pressure at a certain depth, provide a wealth of information about the reservoir and WFT with a HP gauge is used to obtain formation pressure measurements and fluid samples in wells.

In this study, the wireline formation testing and special core analysis data were integrated. From wells J-1, J-2 respectively to investigate the effect of capillary pressure on wireline formation testing measurements. This has been performed through the estimation of the free water level using two different methods.

1.2 Problem Statement

The effects of capillary pressure on wireline formation tester measurements are often manifested in one or both of two ways : Fluid level changes, which affect the position of the free water level with respect to the fluid contacts determined from other open hole log or Gradient changes, which affect the slope and scatter of the gradient lines. This effect requires intensive study in order to quantify this effect in order to get better and sensible interpretation

1.3 Objectives

General objectives:

- To quantify the effect of capillary pressure on wireline formation testing (WFT) measurements.
- To integrate WFT, logging and Capillary pressure data for better reservoir characterization.

Specific objectives:

- Estimation of free-water level using wireline formation testing data.
- Estimation of free-water level from capillary pressure data and correlations.
- Integration of WFT, capillary results with well logs.

Chapter 2: Background and Literature Review

2.1 Introduction

Knowledge of the physical properties of the rock and the existing interaction between the hydrocarbon system and the formation is essential in understanding and evaluating the performance of a given reservoir. Rock properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability.

The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program. There are basically two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks.(Ahmed 1946). these are:

- **Routine core analysis tests:**

This includes: Porosity, Permeability and Saturation.

- **Special tests:**

Overburden pressure, Capillary pressure, Relative permeability, Wettability and Surface and interfacial tension.

2.2 Review of Petro physical Properties

Petro physical properties are determined by performing laboratory analyses on cores from the reservoir to be evaluated. The cores are removed from the reservoir environment, with subsequent changes in the core bulk volume, pore volume, reservoir fluid saturations, and, sometimes, formation wettability. The effect of these changes on rock properties may range from negligible to substantial, depending on characteristics of the formation and property of interest, and should be evaluated in the testing program.

The essential properties for reservoir engineering calculations are the porosity, permeability and saturation. These properties directly affect both the quantity and the distribution of hydrocarbons and, when combined with fluid properties.

The porosity of a rock is a measure of the storage capacity that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume.

$$\varphi = \frac{\text{pore volume}}{\text{bulk volume}} \quad 2.1$$

Many of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity, namely, absolute porosity and effective porosity. The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. It is generally expressed mathematically by the following relationships:

$$\varphi_a = \frac{\text{total volume}}{\text{bulk volume}} \quad 1.2$$

Whereas, the effective porosity is the percentage of interconnected pore space with respect to the bulk volume

$$\varphi = \frac{\text{interconnected volume}}{\text{bulk volume}} \quad 2.3$$

It is the value that is used in all reservoir engineering calculations because it represents the interconnected pore space that contains the recoverable hydrocarbon fluids.

Porosity may be classified according to the mode of origin as original and induced.

The original porosity is that developed in the deposition of the material, while induced porosity is that developed by some geological process subsequent to deposition of the rock.

Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used to determine porosity.

The second important property is the saturation which is defined as that fraction, or percent, of the pore volume occupied by a particular fluid. It is expressed mathematically by the following relationship:

$$\text{fluid saturation} = \frac{\text{total volume of fluid}}{\text{bulk volume}} \quad 2.4$$

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual phase ranges between zero to 100%. By definition, the sum of the saturations is 100% .(Ahmed 1946)

It is of great significance to consider properties which takes into account the interaction between fluids and rocks. One of these properties is the **wettability** which is the preferential affinity of the solid matrix for either the aqueous or oil phases. It can also be defined as the tendency for one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids.(Ahmed 1946). It is normally quantified by the value of the contact angle, such that a value less than 90 degrees indicates a water-wet system, and a value greater than 90 degrees indicates an oil-wet system.

When more than one phase exist in the porous media, we should consider factors which affect their flow within the porous medium, for example, the relative permeability. The Relative Permeability is the ratio of the effective permeability of a fluid at a given saturation to some base permeability. The base permeability is typically defined as:

absolute permeability, k and effective permeability to non-wetting phase at irreducible wetting phase saturation. There are several factors which affect the relative perm abilities. Such as, fluid saturations, geometry of the pore spaces, pore size distribution, wettability and fluid saturation history (i.e., imbibitions or drainage) which will be discussed later.

The importance of the relative permeability data and functions are manifested in its vital applications. They are used in reservoir simulation, flow calculations that involve multi-phase flow in reservoirs and estimation of residual oil and/or gas saturation.

2.3 Fluid Pressure in Hydrocarbon System

Pressure gradient in hydrocarbon system are different from those of water system and are determined by oil gas phase in suite specific gravity ρ_o and ρ_g of each fluid

The pressure gradients are of uncertain of gas and oil but typically are:

$$\left(\frac{\partial p}{\partial D}\right)_w = 0.45 \text{ Psi/ft}$$

$$\left(\frac{\partial p}{\partial D}\right)_o = 0.35 \text{ psi/ft}$$

$$\left(\frac{\partial p}{\partial D}\right)_g = 0.08 \text{ psi/ft}$$

The nature of pressure regimes and the position and recognition of fluid contact are very important to the reservoir in evaluation reserve and determining depletion policy

2.4 Pressure Gradient around the oil Water contact

Water is always present in reservoir rock and pressure in water phase p_w and pressure in the hydrocarbon phase p_o are different. If P is the pressure at the oil-water contact where the water saturation is 100% then the pressure above this contact for the hydrocarbon and water are:

$$p_o = p - gh\rho_w \qquad 2.5$$

$$p_w = p - gh\rho_o \quad 2.6$$

The different between these two pressures is the capillary pressure (p_c)

In the transition zone the phase pressure difference is given by the capillary pressure which is a function of the wetting phase saturation

$$p_c = p_o - p_w \quad 2.7$$

at hydrostatic equilibrium

$$p_{c(s_w)} = \Delta\rho gH \quad 2.8$$

Where : $\Delta\rho = \rho_w - \rho_o$

H: height above free water level

the free water level FWL is not coincident with the oil water contact OWC the water –oil contact corresponds to the depth at which the oil saturation start to increase from water zone. The free water level is the depth at which the capillary pressure is zero.

the difference in depth between the OWC and FWL depends on the capillary pressure which in turn is a function of permeability and grain size .providing the phase is continues the pressure in the respective phase are :

$$p_o = p_{fwl} - \rho_o gh \quad 2.9$$

$$p_w = p_{fwl} - \rho_w gh$$

2.10

On the depth pressure diagram the intersection of the continuous phase pressure line occurs at the free water level.

2.5 Techniques for Pressure Measurement

Earlier test for vertical pressure logging have been replaced by open-hole testing devices that measure the vertical pressure distribution in the well and recover formation samples.

On such device which was introduced in the mid seventies which has established itself in reservoir evaluation is the repeat formation tester RFT. it was initially developed as device to take samples. Over the year however it is main application is to provide pressure depth profiles over reservoir interval.

The device places a probe through the well mud cake and allows small volumes of fluids to be taken and pressure measurement to be made .it can only be operated there for in an open hole environment, the unit can be set at different location in the well and the pressure gradient thereby obtained .this device has been superseded by different tools provided by a number of wire lines service providers. the principle is a same of measuring with a probe in open hole the pressure depth profiles .these open hole pressure measurements have proved valuable at both the appraisal stage and can be used to established fluid contact. (Elsevier.. 1978).

2.6 Uses of Pressure Measurements:

There are several uses and applications of pressure measurements, (Elsevier.. 1978) indicated some of the uses as follows:

- In a virgin reservoir provides a wealth of information about that reservoir.

- They are important in supplementing data unattainable from seismic, survey, cores, conventional logs, and geological study, hence helping to develop static model of the reservoir.
- Distribution of formation pressure across a hydrocarbon reservoir and across it is associated sedimentary basin provides invaluable insight into their history, structure as well as formation and fluid characteristic.
- Pressure gradient identify producible fluid by determining fluid densities and locating fluid contact.
- For fluids identification and for the location of reservoir fluid contact.
- In the more complex case of a develop reservoir, formation pressure can also yield a lot of formation.
- Pressure drop can be used to further our understanding of the reservoir structure by providing away of zoning the reservoir into different layers.

2.7 Capillary pressure

2.7.1 Capillary pressure concepts

Capillary pressure is important in reservoir engineering because it is a major factor controlling the fluid distributions in a reservoir rock. Reservoir rock contains the immiscible phases: oil, water and gas. The force that hold these fluids in equilibrium with each other and with the rock are expressions of capillary force. Capillary pressure is only observable in the presence of immiscible fluids in contact with each other in capillary-like tubes.

Capillary pressure is defined as the pressure difference existing across the interface separating two immiscible fluids. If the wettability of the system is known, then the capillary pressure will always be positive if it is defined as the difference between the pressure in non-wetting phase and wetting phase. That is:

$$p_c = p_{nw} - p_w$$

Where: P_{nw} and p_w are the pressures of the non-wetting and wetting fluids across the inter face, respectively.

The value of capillary pressure is dependent on the saturation of each phase, on which phase is the continuous phase, and on the shape and size of the pores.

An important expression relating the capillary pressure with the radius of the capillary tube and the interfacial tension can be derived by balancing the pressures in the system including the hydrostatic and interfacial tension. Considering a system of oil and water, where water is the wetting fluid, the capillary pressure can be calculated as follows.

$$p_c = \frac{2\sigma_{wo} \cos \theta_{wo}}{r} \quad 2.11$$

Where :

σ_{wo} interfacial tension between the fluids.

θ_{wo} contact angle.

r capillary tube radius .

Considering the same system presented in equation 2.11, it can be shown that the capillary pressure is also related to the height at which the fluid rises inside the capillary tube. This relation is given by:

$$p_c = p_o - p_w = (\rho_w - \rho_o)gh \quad 2.12$$

Where p_o and p_w are the oil (non-wetting fluid) and water (wetting fluid) pressures across the interface, respectively; ρ_w and ρ_o are the oil and water densities, respectively ; g is the acceleration due to gravity, and h is the height of the column of water in the capillary tube with respect to a reference point .

Capillary pressure may also be described using a more complex equation called the Laplace equation:

$$p_c = \sigma \left(\frac{1}{r_1} + \frac{1}{r_2} \right) \quad 2.13$$

Where p_c capillary pressure is σ is interfacial tension, and r_1 and r_2 are the principal radii of curvature.

2.7.2 Capillary pressure curve:

It is impossible to use the equations presented so far (Laplace and capillary tubes) to calculate the capillary pressure on porous media due to the complex structure of the pores. In laboratory, capillary pressure is measured as a function of the saturation of the wetting phase. Capillary pressure can be viewed as the necessary pressure to force non-wetting fluid to displace the wetting fluid in a capillary.

The water tends to rise inside the rock pores due to the rock surface preference to this fluid. The height at which the water rises in the rock depends on the capillary pressure between the water and the oil. Rocks usually have pores of different radius. Therefore, a particular capillary pressure will be associated with a specific set of pores having the same “radius” lower capillary pressure will displace water out of bigger pores while higher capillary pressures are required to displace water out of smaller pores.

The capillary pressure curve for a porous medium is a function of pore size, pore size distribution, pore geometry, fluid saturation, fluid saturation history or hysteresis, wettability, and interfacial tension.

It is common to plot two curves – as shown in Figure 2.1 for the drainage process which represents the displacement of the wetting phase by the non-wetting phase, the second one is for the imbibitions process which represents the displacement of the non-wetting phase by the wetting phase.

The imbibitions curve presents lower capillary pressures for a fixed saturation than drainage curves because of the natural tendency of the wetting fluid to saturate the rock.

For the drainage curve, a capillary pressure greater than zero is required to force the non-wetting fluid into the rock . The difference between saturations at the end points of both curves is the residual saturation of the non-wetting fluid that is trapped inside the rock .(Chen 2003).

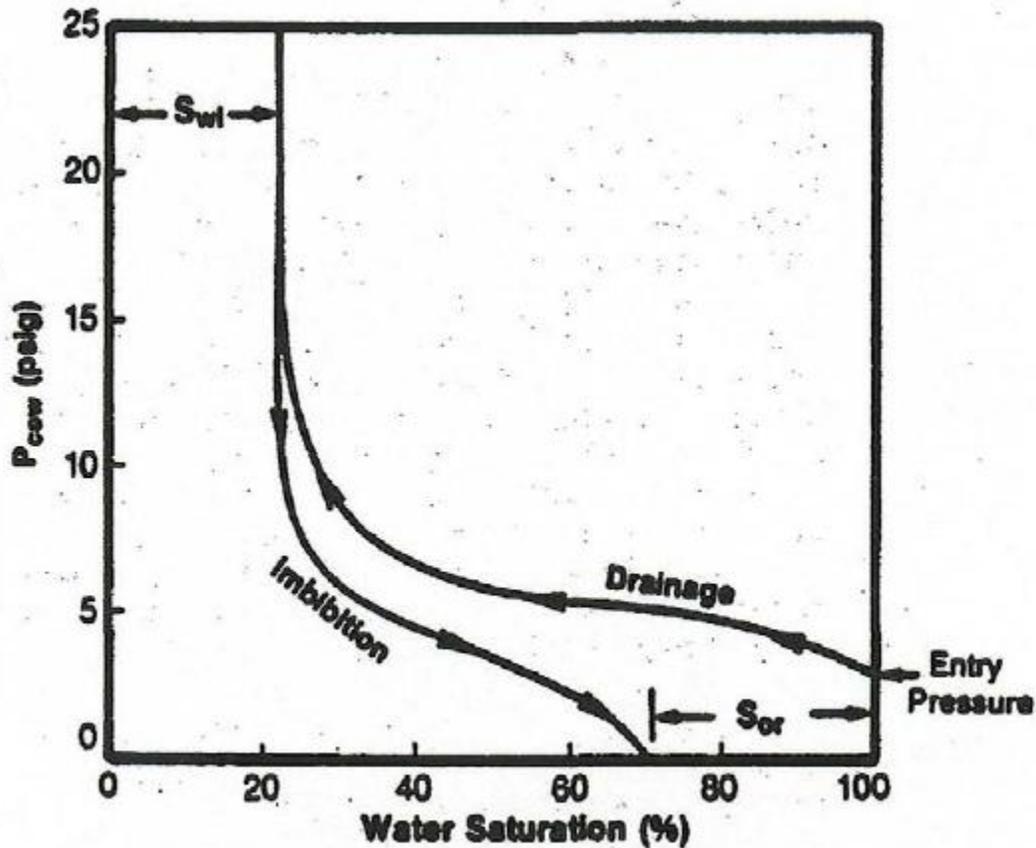


Figure 2.1: Imbibitions & Drainage capillary pressure curve. (Chen 2003)

2.7.3 Capillary Pressure Measurements

There are various experimental methods for capillary pressure measurement. Here are four types of methods.

2.7.3.1 Centrifugal method

Centrifugal method is required for three main steps:

- Step 1 : Rotate at a fixed constant speed, the centrifugal force displaces some liquid, which can be read at the window using strobe light. Thus, the saturation can be obtained.
- Step 2 : The speed of rotation is converted to capillary pressure using appropriate equation.
- Step 3 : Repeat for several speeds and plot capillary pressure with saturation.

There are some advantages and disadvantages of this method. The advantages are shown in results can be obtained fairly quickly (hours, days, weeks), reasonably accurate and can use reservoir fluids. On the other hand, the disadvantage of this method is the fact that complex analysis required can lead to calculation errors.

2.7.3.2 Mercury injection method

There are three steps:

- Step 1 : Place core sample in chamber and evacuate it.
- Step 2 : Force mercury in under pressure. The amount of mercury injected divided by the pore volume is the non-wetting phase saturation. The capillary pressure is the injection pressure.
- Step 3 : Continue for several pressures and plot the pressure against the mercury saturation.

There are advantages and disadvantages of this method. The advantages are present in results obtained quickly (minutes, hours), method is reasonably accurate, very high range of capillary pressures and no threshold pressure. Otherwise, the disadvantages are ruins core / mercury disposal, hazardous testing material (mercury) and conversion required between mercury/air capillary data to reservoir fluid systems.

2.7.3.3 Porous diaphragm method

Porous diaphragm method is needs for steps:

1. Saturate both the core sample and diaphragm with the fluid to be display.
2. Place the core in apparatus.
3. Apply level of pressure; wait for the core to reach static equilibrium.
4. The capillary pressure = height of liquid column +applied pressure.
5. Increase the pressure and repeat step 3.
6. Plot capillary pressure versus saturation.

They are some advantages and disadvantages of this method. The advantages are shown in very accurate and can use reservoir fluids. On other hand, the disadvantages very slow (weeks, months) to reach the equilibrium and have to work within threshold pressure of the diaphragm.

2.7.3.4 Other method

Simultaneous steady flow of two fluid is established in the core, Using special wetted discs , the pressure of two fluid in the core is measured (The difference =capillary pressure) , Change the rate of one fluid and saturation change, Plot capillary pressure vs. saturation .

Field method

A long column of porous medium put in the contact with a wetting fluid at its base and suspended in the earth's gravitational field. It is left to reach equilibrium, samples are taken at different heights and the capillary pressure calculating using $p_c = \rho gh$, Disadvantage of this method is may take very long to reach equilibrium.(Clars 1960)

2.7.4 Fluid distribution in the reservoir

Figure 2 shows the water saturation distribution as a function of distance from the free-water level in an oil-water system. It is essential at this point to introduce and define four important concepts:

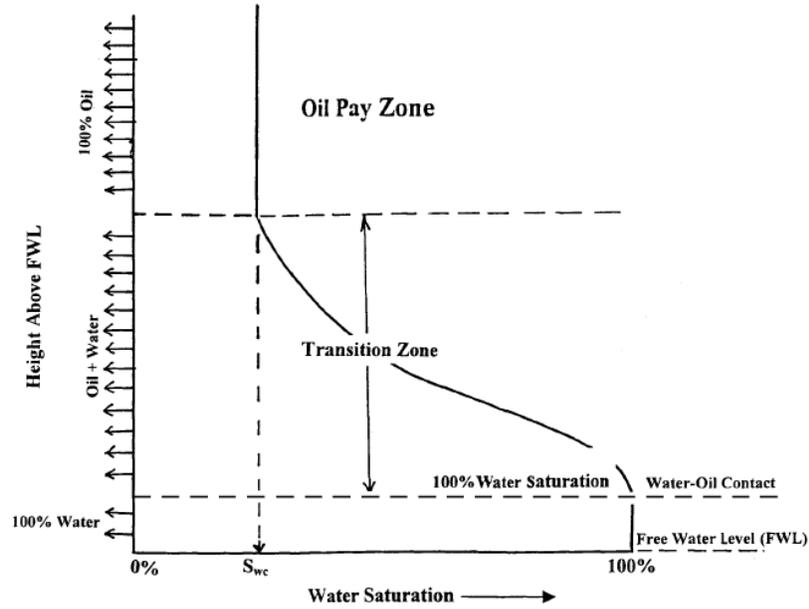


Figure 2.2: Water Saturation Profile (Ahmed 1946)

Transition zone define as the vertical thickness over which the water saturation ranges from 100% saturation to irreducible water saturation S_{wc} .

Water oil contact: is the level at which the hydrocarbon saturation starts to increase from some minimum saturation. In a water-wet rock, that minimum saturation is essentially zero.

Gas oil contact: is the minimum depth at which a 100% liquid, i.e., oil + water, saturation exists in the reservoir

Free water level : define as the oil-water capillary pressure equal zero .(Ahmed 1946)

$$FWL = WOC + \frac{144 p_c}{\Delta\rho} \quad 2.14$$

Where:

h the height h above the free water level.

$$h = \frac{144 p_c}{\Delta\rho} \quad 2.15$$

2.7.5 Converting laboratory capillary pressure data to reservoir capillary pressure data

Water (brine) – oil capillary pressure data are difficult to measure in laboratory. Generally, air-brine or air-mercury data are measured instead and it becomes necessary to convert these data to equivalent oil-water data representative of reservoir fluids. If we denote $(p_c)_{aw}$ or $(p_c)_{a\ Hg}$ as $(p_c)_{lab}$ and $(p_c)_{ow}$ as $(p_c)_{res}$ conversion equation can be derived as follows :

$$(p_c)_{lab} = \frac{2\sigma_{aw} \cos \theta_{aw}}{r} \quad 2.16$$

$$r = \frac{2\sigma_{aw} \cos \theta_{aw}}{(p_c)_{lab}} \quad 2.17$$

$$(p_c)_{res} = \frac{2\sigma_{ow} \cos \theta_{ow}}{r} \quad 2.18$$

$$r = \frac{2\sigma_{ow} \cos \theta_{ow}}{(p_c)_{res}} \quad 2.19$$

Assuming that the same porous medium applies in both laboratory and field, we obtain

$$(p_c)_{res} = \frac{2\sigma_{ow} \cos \theta_{ow}}{2\sigma_{aw} \cos \theta_{aw}} (p_c)_{lab} \quad 2.20$$

Neglecting the contact angle

$$(p_c)_{res} = \frac{2\sigma_{ow}}{2\sigma_{aw}} (p_c)_{lab} \quad 2.21$$

An identical equation would be obtained by starting from the two equations:

$$\left(\frac{1}{r_1} + \frac{1}{r_2}\right)_{lab} = (p_c)_{lab} \quad 2.22$$

$$\left(\frac{1}{r_1} + \frac{1}{r_2}\right)_{res} = (p_c)_{res} \quad 2.23$$

Assuming the radius of curvature in the laboratory is the same as that in the reservoir:

$$(p_c)_{res} = \frac{\sigma_{res}}{\sigma_{lab}} (p_c)_{lab} \quad 2.24$$

2.7.6 Application and uses of capillary pressure data

Capillary pressure can be used by geologists, petro physicists and petroleum engineers to evaluate the following:

- Reservoir rock quality.
- Pay versus nonpaid.
- Expected fluid saturation.
- Seal capacity.
- Depth of the reservoir.
- Thickness of the transition zone.
- An approximation of the recovery efficiency.

Application:

- Determine fluid distribution in reservoir (initial conditions)
 - Accumulation of HC is drainage process for water wet reservoir.
 - S_{wc} function of height above OWC (oil water contact)
- Determine recoverable oil for water flooding applications.
 - Imbibitions process for water wet reservoirs.

- Pore Size Distribution Index
 - Absolute permeability (flow capacity of entire pore size distribution)
 - Relative permeability (distribution of fluid phases within the pore size distribution)
- Reservoir Flow - Capillary Pressure included as a term of flow potential for multiphase flow.
- Input data for reservoir simulation models.

2.8 Wireline Formation Tester

Wire line formation testers such as the well-established Repeat Formation Tester (RFT) and the more recent Modular Dynamics Tool (MDT) measure the pressure of the continuous phase present in the invaded region, which is typically drilling fluid filtrate. Conventional interpretation techniques have often assumed this pressure identical to the pressure of the continuous phase in the virgin region of the formation, i.e., formation fluid pressure. As such, a series of pressure measurements at different depths would be expected to consistently yield a pressure gradient corresponding to the density of the formation fluid. More recent work has pointed out that this assumption cannot be entirely correct, otherwise it would appear that most formation tester surveys are anomalous. In reality, because the concepts of free fluid level, fluid contacts, rock wettability, and pore fluid pressures are so closely related, the measured tester pressure cannot be simply identical to formation pressure. Rather, it is **different** from the formation fluid pressure by the amount of capillary pressure, which is itself mainly a function of the wetting phase saturation.

2.9 Literature Review

H.elshahawi, K.fathy, and S.Lhieka, explores the effects of capillary pressure and wettability on wire line formation tester measurement as manifested in three ways:

2.9.1 Reservoir statics pressure gradient

All petroleum reservoirs saturated with water before oil migrated into the reservoir displacing the water. The resulting fluid distribution is governed by the equilibrium between gravitational and capillary forces .in the case of water-wet reservoir this distribution is simulated by a drainage capillary pressure curve. Using a FWL as the different datum, the water and oil phase pressure at a distance z above the FWL datum are given by the following two expressions:

$$p_w(z) = p_{fwl} - \rho_w g z \quad 2.25$$

$$p_o(z) = p_{fwl} - \rho_o g z \quad 2.26$$

The capillary pressure provided the two phases are continuous:

$$p_c(z) = \frac{\Delta \rho g z}{144} \quad 2.27$$

In water wet reservoir the free water level occur at depth d_o below the OWC given by:

$$d_o = \left(\frac{p_d}{\Delta \rho g} \right) \times 144 \quad 2.28$$

p_d is the displacement pressure

The capillary transition zone is the region above the OWC, the height of the transition zone is a function of wettability, the fluid density contrast ,and the oil water interfacial tension .the elevation (h) above the OWC of any particular saturation within the transition zone is given by :

$$h(s_w) = \left(\frac{P_{c(s_w)} - p_d}{\Delta \rho g} \right) * 144 \quad 2.29$$

in an oil wet reservoir the situation described above is slightly different .it is the water that is the non wetting phase, and hence its pressure is higher than it would be in a water-wet medium.OWC in this case is lowest level that the oil will reach (at which the oil saturation will start to increase from its minimum value) the FWL is located above the OWC by a distance d_o given by:

$$d_o = (p_d / \Delta \rho g) * 144 \quad 2.30$$

This is generally larger than the equivalent distance in water wet rock.

2.9.2 Tester gradient measurement

Capillary pressure difference will exist between the oil and water in the capillary transition zones by virtue of the very existence of that transition zone. despite this and despite the fact that the tool actually draws mud filtrate into its small test chamber conventional formation tester interpretation methods assume that the tool measures the true formation pressure of the continuous mobile formation fluid in the virgin zone.

For a drilled with water based mud in a water wet formation, the oil in the flushed zone of an oil bearing interval is close to residual saturation so that the capillary pressure in the invaded zone become small, in the water bearing interval there will be no capillary pressure difference between the mud filtrate and the formation water, and the tool measure the true formation pressure.

For a well drilled with oil-based mud in a water -wet formation ,there is no capillary pressure difference between the mud filtrate and the formation oil in an oil-bearing interval so the tool measure the actual formation gradient ,in the water-bearing zone the water saturation in the invaded zone is close to connate and the capillary pressure is large.

For a well drilled with water-based mud in an oil-wet formation, the oil in the flushed zone of an oil-bearing interval is close to residual saturation, and the capillary pressure is maximum. The measured water phase pressure is higher than the oil phase pressure by the amount of p_c . In the water bearing interval there will be no capillary pressure difference between the mud filtrate and the tool joint, and the tool joint measures the true formation gradient.

For a well drilled with oil-based mud in an oil wet formation there is no capillary difference, in the water bearing zone the water saturation in the invaded zone is close to irreducible and the p_c is small. The result is that the measured oil pressure is slightly lower than the desired water pressure, when the two phase becomes discontinuous at low saturation its pressure follows the gradient of the other continuous phase.

2.9.3 Tester fluid level measurements

The effects of wettability and capillary pressure on the wire line formation tester's fluid measurement are closely linked to their effects on gradient measurement

In a water wet medium, the capillary pressure in the oil filled pores are higher than in the water-filled ones, and the FWL is located below the OWC by a distance determined by the capillary pressure threshold (Figure 2.3) with water-base mud (WBM) in the oil zone, the measured pressure will be the water phase pressure, which will be lower than the oil phase pressure we are aiming to measure. Therefore, the measured oil line will be shifted to the left of the true formation oil pressure line, making the intersection higher than the actual FWL (left plot of Figure 2.4). On the other hand, with an oil-based mud (OBM), the measured pressure is the oil filtrate pressure, which will be greater than the water phase pressure. Thus, the measured pressure line will be shifted to the right of the true formation water pressure line, making the intersection again higher than the actual FWL (right plot of Figure 2.4).

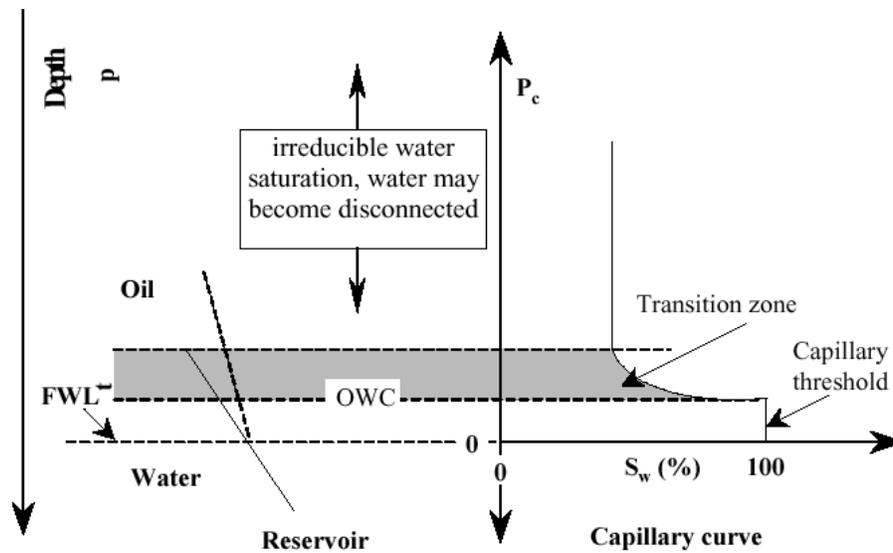


Figure 2.3: fluid pressure, capillary pressure, and saturation distribution in a water-wet reservoir. . (H.Elshahawi 1999).

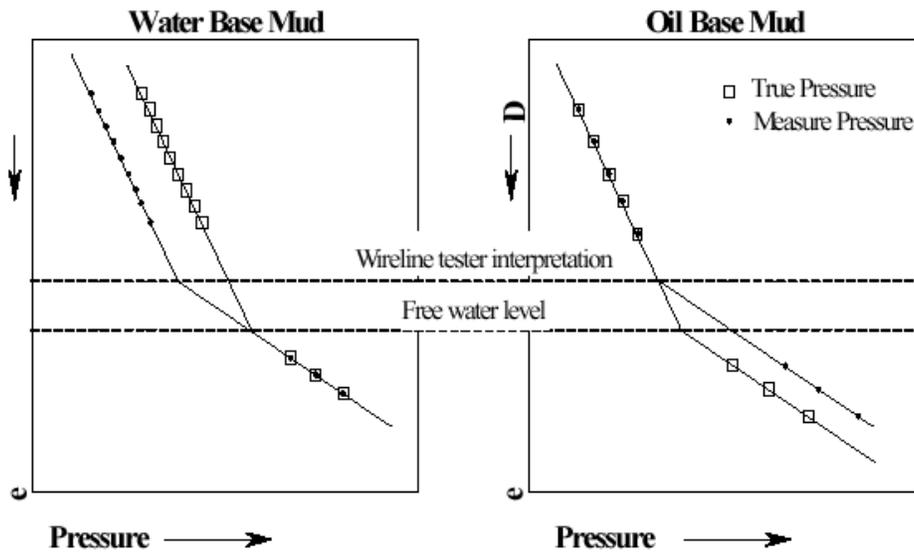


Figure 2.4: capillary pressure effects on pressure measurement in a water wet system. . (H.Elshahawi 1999).

In an oil-wet medium, the capillary pressures in the water-filled pores are higher than in the oil-filled pores, and the FWL is located above the OWC by a distance again determined by the capillary threshold or displacement pressure Figure 2.6. With a WBM

in the oil zone, the measured pressure will be the water phase pressure, which will be higher than the oil phase pressure we are aiming to measure. Therefore, the measured oil line will be shifted to the right of the true formation oil pressure line, making the intersection lower than the actual FWL (left plot of Fig.6). On the other hand, with (OBM) in the water zone, the measured pressure is the oil filtrate pressure, which will be lower than the water phase pressure. Thus, the measured water line will be shifted to the left of the true formation water pressure line, making the intersection again lower than the actual FWL (right plot of Figure 2.6).

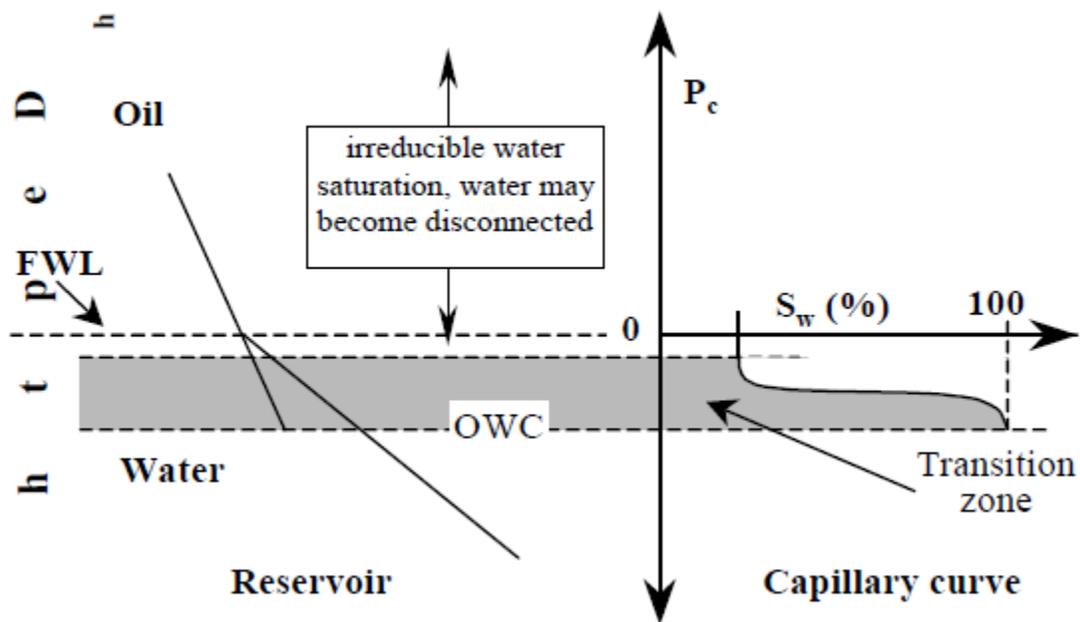


Figure 2.5: Fluid pressure, capillary pressure, and saturation distribution an oil-wet reservoir (H.Elshahawi 1999).

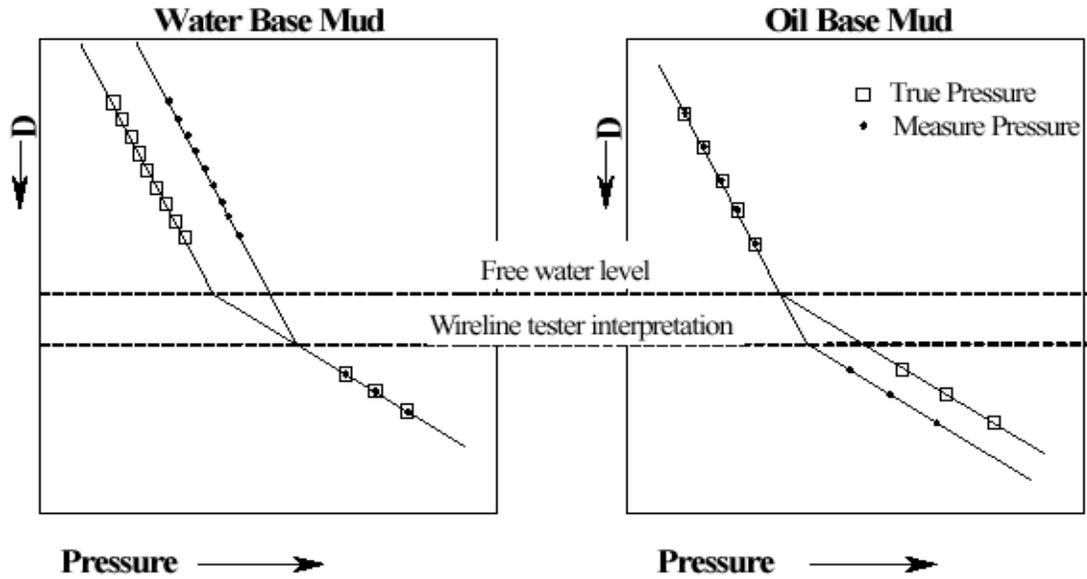


Figure 2.6: capillary pressure effects on pressure measurement in an oil wet system.
. (H.Elshahawi 1999).

1.8.4 Correcting for wettability and capillary pressure effects on the formation tester:

correcting for wettability and capillary pressure effects on wire line formation tester pressures is to construct the Leveret J-function for the reservoir from core samples and transform it to reservoir fluid conditions, by knowing the invaded zone saturation .better still ,if a nuclear magnetic resonance (NMR)log is available , then the down hole capillary pressure correction can be computed directly. (H. Elshahawi 1999).

Chapter 3: Methodology

3.1 Problem description

The effects of capillary pressure on wire line formation tester measurements are often manifested in fluid level change, which affect the position of the free water level with respect to the fluid contacts determined from capillary pressure data .or gradient changes, which affect the slope and scatter of the gradient lines.

3.2 Data description

3.2.1 WFT data

WFT data were selected from **J1** to evaluate pressure gradient, two section intervals were planned for testing. Test interval between 1507m to 1588m.

Table 3.2-1: WFT data

depth, m	pressure, psi	remark	depth, m	pressure, psi	remark
1507	1970.1	Normal	1542	2010.6	Normal
1508	1971.5	Normal	1543	2014.9	Normal
1509	1973.1	Normal	1544	2017.6	Normal
1521	1994.4	Normal	1546	2015	Normal
1522	1995.8	Normal	1555	2028	Normal
1523	1997	Normal	1556	2029.7	Normal
1524		Lost Seal - Soft Formation	1558	2032	Normal
1528.5	2000.5	Normal	1559	2034	Normal
1529.5	2000.8	Normal	1561	2036.8	Normal
1531	2050.8	Supercharged	1581	2064.7	Normal
1533.5	2006.3	Normal	1583	2067.4	Normal
1534.5	2007.7	Normal	1585	2070.3	Normal
1539.4		Dry Test	1587	2073.2	Normal
1540	2009.2	Normal	1588	2074.6	Normal

3.2.2 Capillary pressure data

Capillary pressure curve and pore size distribution data were selected from J2 deduce from two methods:

3.2.2.1 Mercury injection

Three trim samples were selected to perform mercury injection analysis to compute pore size distribution and capillary pressure curve.

Table 3-2: 1st sample (1450.87m)

$P_{c\ lab}$	S_w	$P_{c\ lab}$	S_w	$P_{c\ lab}$	S_w
0.517	1	23.638	0.085	1262.699	0.011
0.586	1	25.086	0.081	1338.386	0.01
0.584	1	26.575	0.08	1420.486	0.009
0.659	0.966	28.189	0.078	1505.785	0.009
0.676	0.965	29.886	0.076	1596.628	0.008
0.735	0.958	31.743	0.076	1693.227	0.007
0.761	0.956	33.666	0.075	1795.179	0.007
0.825	0.944	35.538	0.073	1903.04	0.006
0.874	0.94	38.016	0.072	2017.394	0.006
0.922	0.93	40.352	0.071	2138.763	0.005
0.973	0.922	43.919	0.069	2269.201	0.005
1.034	0.904	46.024	0.068	2404.938	0.004
1.092	0.891	48.325	0.066	2549.806	0.004
1.155	0.872	52.518	0.065	2703.459	0.003
1.225	0.844	54.964	0.064	2867.257	0.003
1.295	0.817	59.12	0.063	3038.958	0.003
1.373	0.764	62.362	0.061	3223.067	0.002
1.451	0.714	65.612	0.06	3415.411	0.002
1.545	0.657	70.296	0.059	3620.905	0.002

Table 3.2-3: 2nd sample (1454.84m)

P_{c lab}	S_w	P_{c lab}	S_w	P_{c lab}	S_w
0.517	1	23.638	0.311	1191.58	0.046
0.586	1	25.086	0.305	1262.595	0.043
0.584	1	26.575	0.3	1338.279	0.04
0.659	1	28.189	0.295	1420.376	0.038
0.676	1	29.886	0.29	1505.672	0.035
0.735	0.996	31.896	0.286	1596.513	0.033
0.761	0.995	33.816	0.283	1693.11	0.031
0.825	0.991	35.685	0.279	1795.059	0.029
0.874	0.989	38.159	0.276	1902.918	0.027
0.922	0.987	40.491	0.271	2017.271	0.025
0.973	0.984	44.053	0.266	2138.638	0.023
1.034	0.982	46.155	0.263	2269.075	0.022
1.092	0.98	48.451	0.258	2404.81	0.02
1.155	0.977	52.639	0.253	2549.677	0.019
1.225	0.975	55.08	0.249	2703.329	0.018
1.295	0.973	59.232	0.245	2867.125	0.017
1.373	0.971	62.47	0.241	3038.825	0.016
1.451	0.967	65.714	0.236	3222.934	0.015
1.545	0.964	70.394	0.231	3415.277	0.014
1.634	0.961	74.483	0.227	3620.769	0.013
1.734	0.958	79.58	0.222	3839.19	0.012
1.835	0.956	84.699	0.218	4069.818	0.011
1.937	0.953	90.139	0.213	4312.178	0.011
2.048	0.949	94.903	0.209	4570.25	0.01
2.171	0.945	101.435	0.204	4844.555	0.009
2.3	0.941	105.929	0.2	5136.975	0.009
2.438	0.936	113.812	0.195	5446.378	0.008
2.585	0.929	120.195	0.191	5776.57	0.008
2.736	0.922	128.385	0.187	6124.166	0.007

Table 3-4: 3rd sample (1456.30m)

$P_c lab$	S_w	$P_c lab$	S_w	$P_c lab$	S_w
0.523	1	26.576	0.218	1339.568	0.037
0.588	1	28.2	0.214	1420.96	0.036
0.589	1	29.897	0.209	1506.878	0.035
0.66	1	31.012	0.206	1598.064	0.034
0.688	1	33.1	0.202	1693.912	0.033
0.737	1	35.529	0.198	1794.683	0.032
0.773	0.999	37.765	0.194	1903.263	0.031
0.831	0.997	40.148	0.191	2019.09	0.03
0.876	0.996	43.183	0.185	2140.054	0.029
0.929	0.994	45.435	0.182	2268.096	0.029
0.974	0.992	49.034	0.177	2402.768	0.028
1.039	0.991	52.656	0.173	2550.121	0.027
1.097	0.99	55.154	0.169	2703.775	0.027
1.159	0.989	58.979	0.165	2867.373	0.026
1.227	0.986	63.126	0.16	3039.371	0.026
1.299	0.985	66.957	0.158	3221.589	0.025
1.375	0.984	71.24	0.154	3415.175	0.025
1.46	0.981	74.507	0.151	3621.829	0.025
1.549	0.98	79.11	0.147	3839.141	0.024
1.64	0.979	83.662	0.144	4069.356	0.024
1.737	0.977	89.421	0.141	4315.328	0.023
1.838	0.975	94.759	0.137	4568.94	0.023
1.938	0.973	100.267	0.134	4846.999	0.023
2.057	0.971	106.407	0.13	5137.112	0.023
2.176	0.969	112.773	0.127	5448.537	0.022
2.306	0.965	119.323	0.124	5775.815	0.022
2.445	0.962	128.141	0.121	6124.843	0.022
2.592	0.956	135.69	0.119	6494.061	0.022
2.741	0.948	143.007	0.116	6885.85	0.021
2.905	0.929	152.534	0.113	7300.252	0.021

3.2.2.2 Porous diagram method

Capillary pressure curve were determined from primary drainage process using porous diagram method. Lab oil/water system was used for two sample core plugs selected from J2.

Table 3-5: 1st sample (1448.27m)

$P_{c\ lab}$	S_w
0	1
1.45	0.299
2.9	0.241
5.8	0.241
14.5	0.241
29	0.232
72.5	0.232

Table 3.2-6: 2nd sample (1455.10m)

$P_{c\ lab}$	S_w
0	1
1.45	0.597
2.9	0.401
5.8	0.381
14.5	0.355
29	0.329
72.5	0.313

3.3 Data quality check and quality assurance

Analysis of WFT data, there is 28 pretest points in the well, 25 pretests points are good and are adopted to perform pressure and fluid type analysis, the other 3 were rejected due to failure; lost seal-soft formation, supercharged and dry test.

Analysis of fluid type, totally 25 pretest points have been analyzed used to perform advanced pressure analysis and to determine formation fluid type these reliable pretest points can be divided into 2 groups:

Group1 (1521m-1534m):

There are 4 points in this group. Their R-square is 0.998, so they can be grouped.

Group2 (1543m-1588m):

There are 10 points in this group. Their R-square is 0.999, so they can be grouped.

Assumption of capillary pressure data:

- In mercury method when started the calculation observed that the saturation after a certain period will remain constant.
- Table of typical interfacial tension and contact angle constant:

System	θ	σ
Laboratory Oil-water	30	48
Air-mercury	140	480
Reservoir Oil-water	30	30

3.4 Pressure gradient estimation

It is the difference in the fluid densities, a difference in the pressure gradient occurs during the measurement. and obtained by inversely slope from plot depth versus formation pressure. The ranges which have been used in this study were as follows.

- Gas gradient ranges from (<0.1) psi/ft.
- Oil gradient ranges from (0.28 – 0.39) psi/ft.
- Water gradient ranges from (0.433 – 0.465) psi/ft.
- Fresh water gradient = 0.433 psi/ft.
- Saline water gradient = 0.465 psi/ft.

3.5 P_c Calculation

There are many steps to obtain FWL from capillary pressure data:

Step 1: converting laboratory capillary pressure data to reservoir condition.

$$(P_c)_{res} = (P_c)_{lab} \frac{(\sigma \cos \theta)_{res}}{(\sigma \cos \theta)_{lab}} \quad 3.1$$

Step 2:

- averaging capillary pressure data using the leveret J-function.

$$J(S_w) = 0.2164 \frac{P_c}{\sigma \cos \theta} \sqrt{\frac{K_{avr}}{\phi_{avr}}} \quad 3.2$$

$$\phi_{avr} = \phi_1 + \phi_2 + \dots + \phi_n$$

$$K_{avr} = (k_1 * k_2 * \dots * k_n)^{\frac{1}{n}}$$

- Plot S_w versus $J(S_w)$ for all sample and obtained power trend line.

Assume S_w -from initial water saturation to 100%- and find $J(S_w)$ from power trend line.

$$J(S_w) = aS_w^b \quad 3.3$$

Step 3: calculate capillary pressure:

$$P_c = \frac{\sigma \cos \theta J(S_w)}{0.2164 \sqrt{\frac{K_{avr}}{\phi_{avr}}}} \quad 3.4$$

Step 4: calculate height above FWL

$$H = 7.19706 \frac{P_c}{\Delta \rho} \quad 3.5$$

Step 5: calculate FWL

$$FWL = OWC + 144 \frac{P_d}{\Delta \rho} \quad 3.6$$

Chapter 4: Results and Discussions

4.1 Capillary pressure

Step 1: the laboratory capillary pressure data were converted to reservoir condition by using equation 3.1 plotted in below Figure 4.1, Figure 4.2 and Figure 4.3 using mercury injection and Figure 4.4, Figure 4.5 using porous diagram.

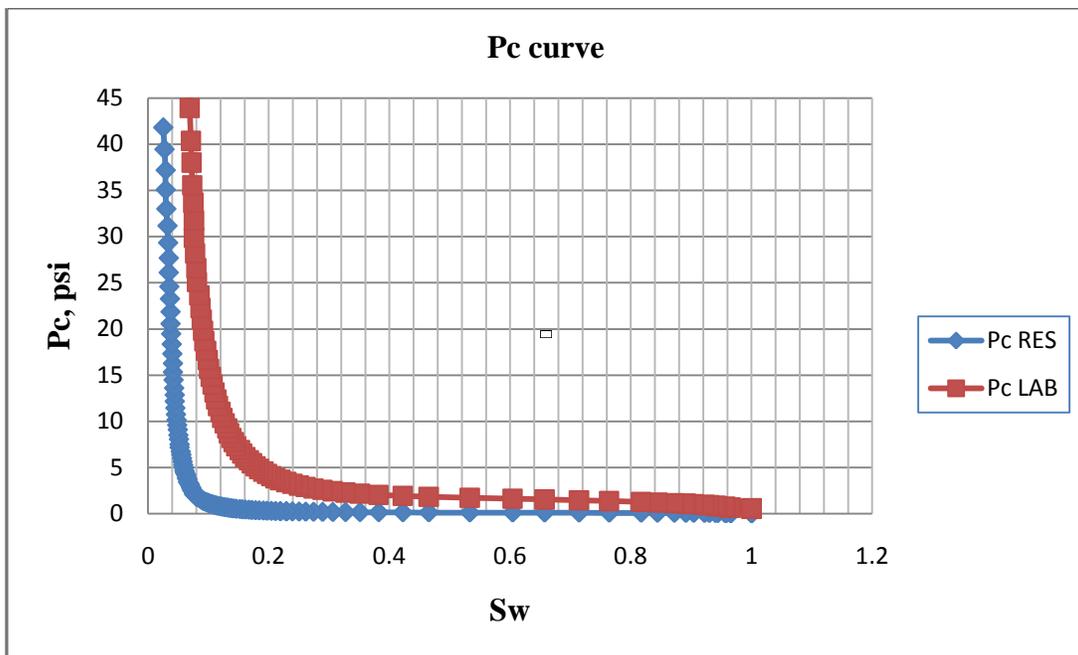


Figure 4.1: curve for 1st sample using mercury injection

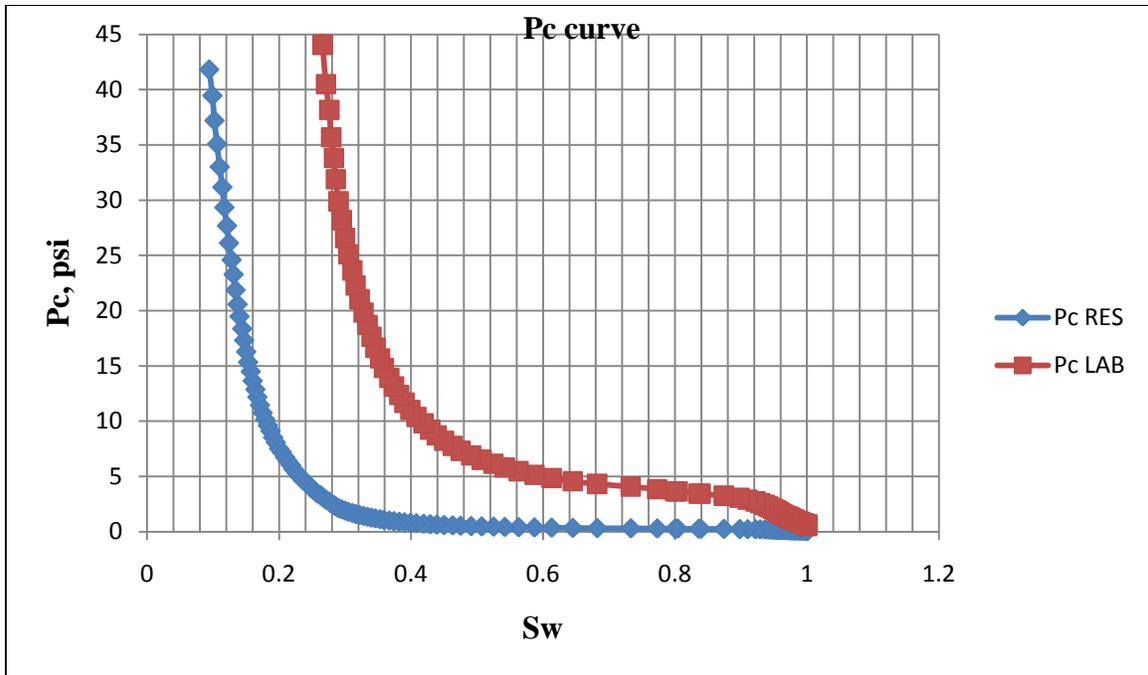


Figure 4.2: curve for 2nd sample using mercury injection

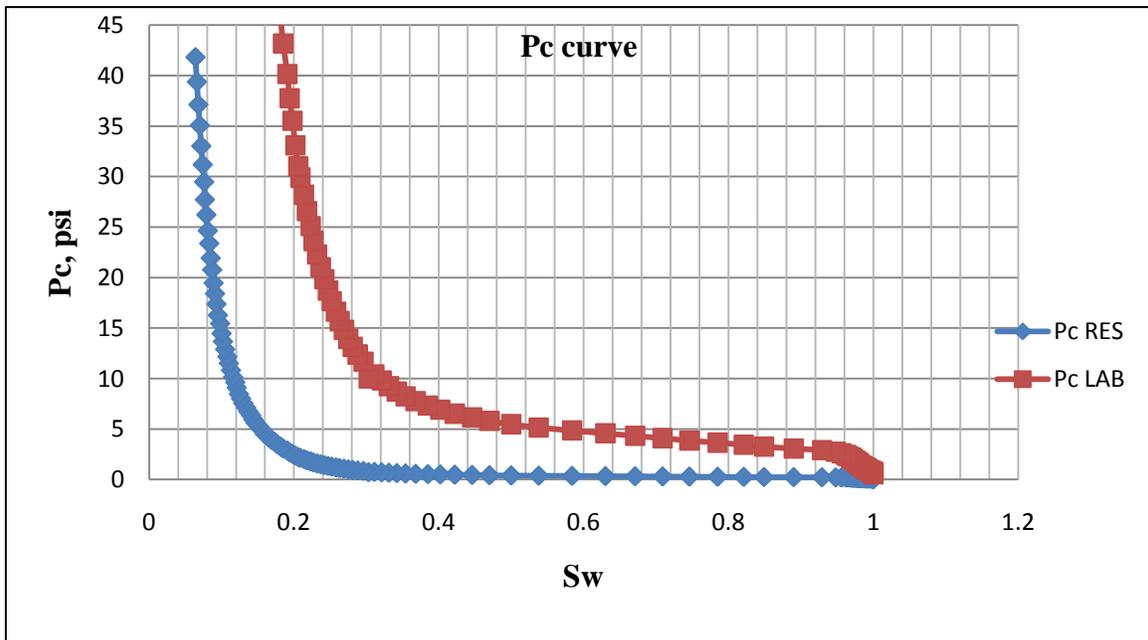


Figure 4.3: Pc curve for 3rd sample using mercury injection

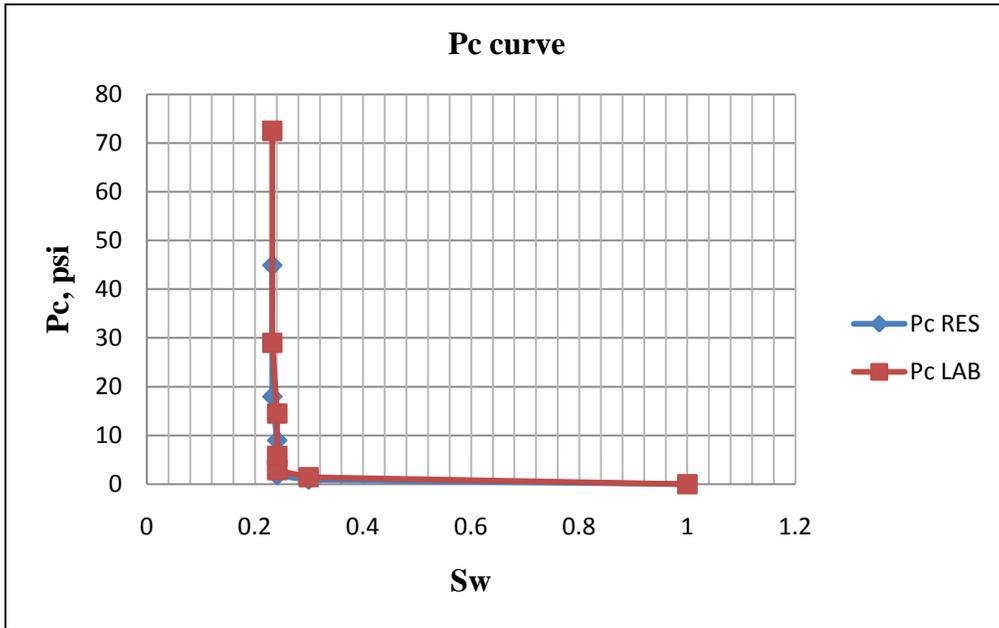


Figure 4.4: curve for 1st using porous diagram

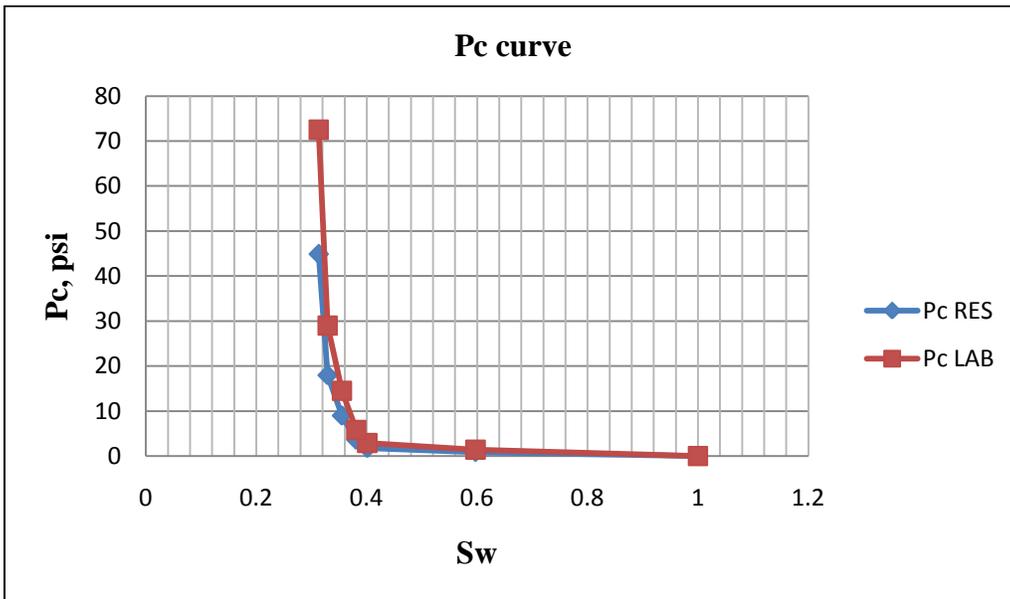


Figure 4.5: Pc curve for 2nd sample using porous diagram

Step 2:

- averaging capillary pressure data using the leveret J-function using equation 3.2.

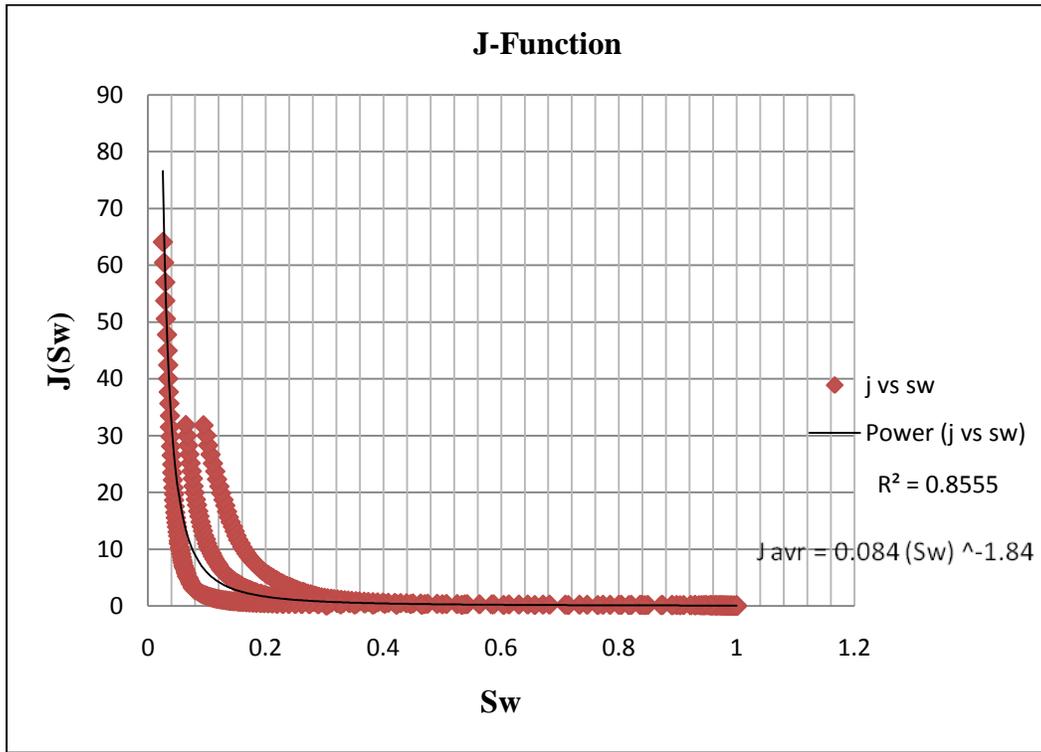


Figure 4.6: J-function using mercury method

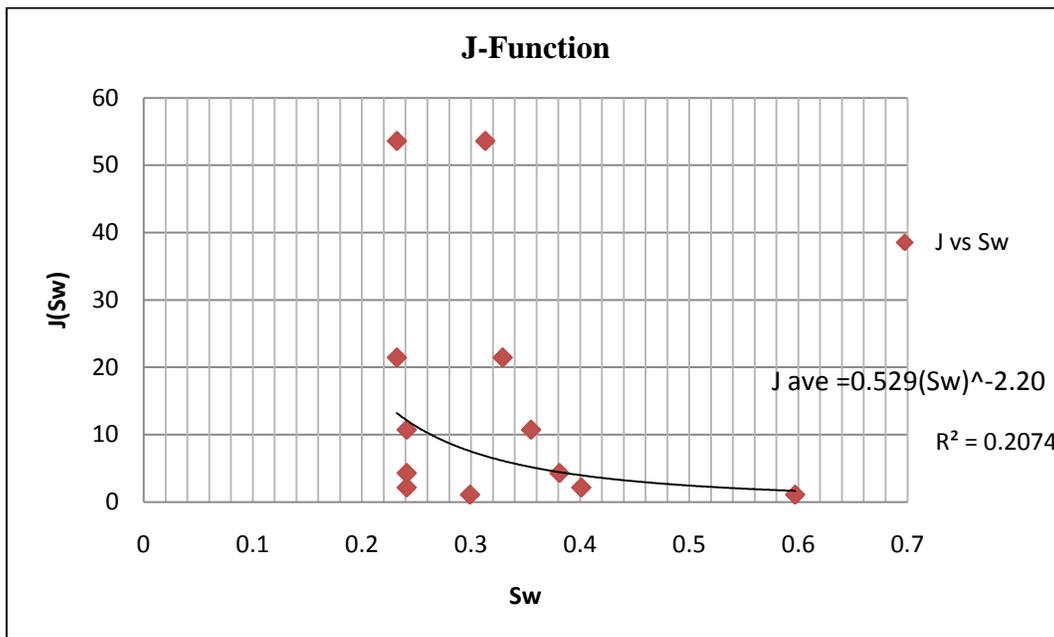


Figure 4.7: J-function using diagram method

- Assume S_w -from initial water saturation to 100%- and find $J(S_w)$ from power trend line using equation 3.3.

Step3:

Capillary pressure was calculated using equation 3.4.

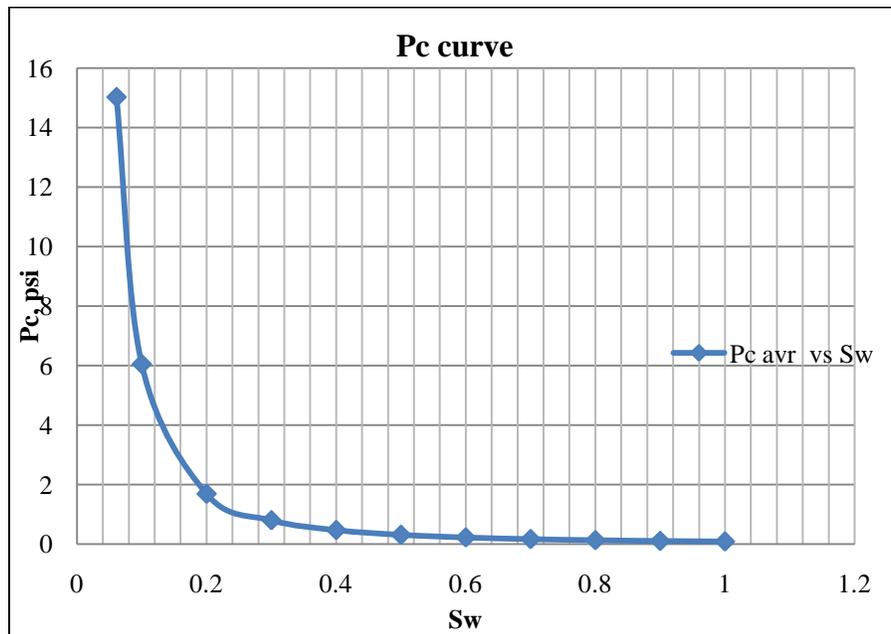


Figure 4.8: Pc curve using mercury method

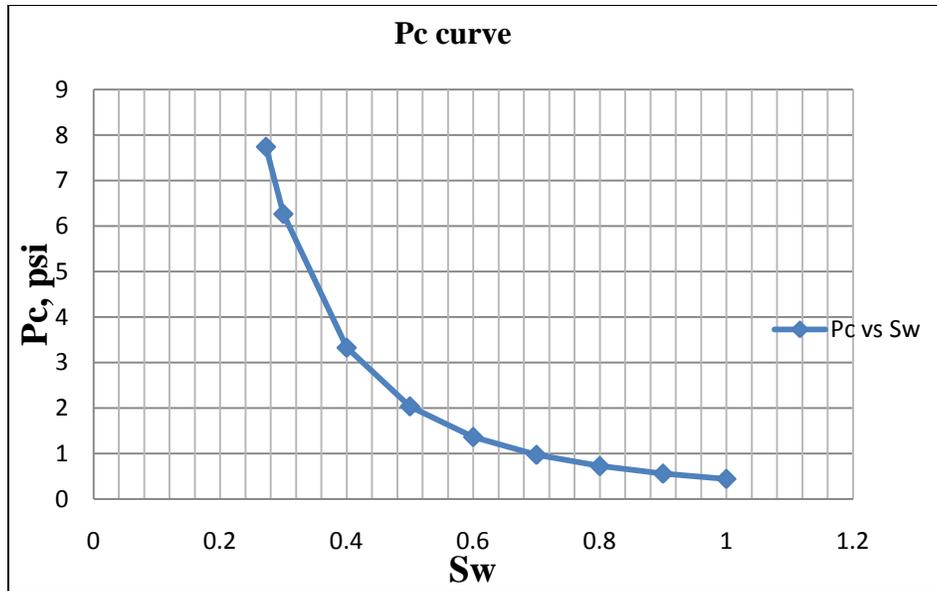


Figure 4.9: Pc curve using diagram method

Step 4: Height above FWL was calculated using equation 3.5.

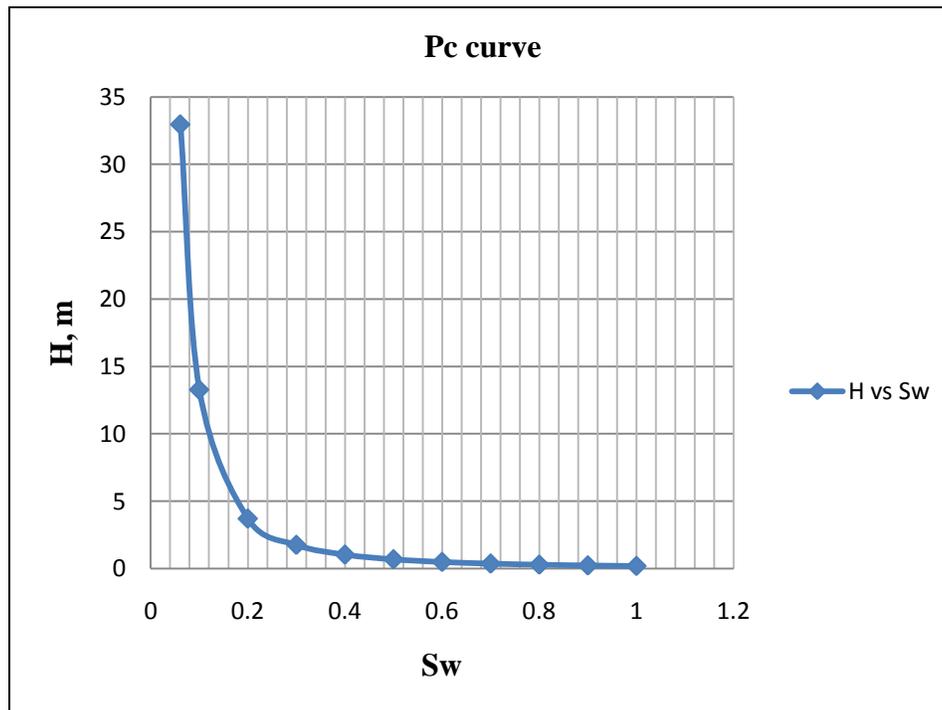


Figure 4.10: height above FWL using mercury injection

Above figure height above FWL was calculated by mercury injection = 32.95m, initial water saturation 0.061 and FWL = 1550m

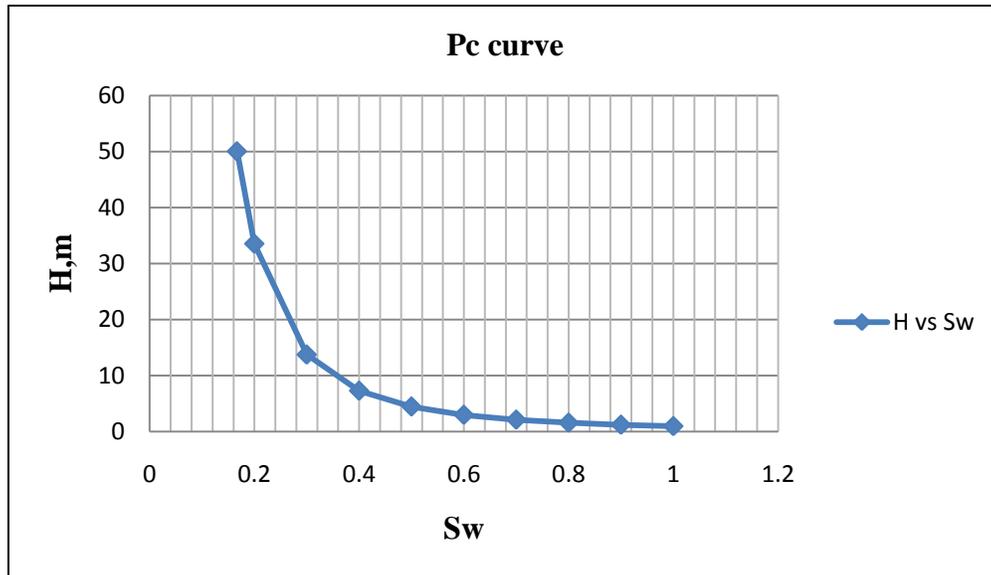


Figure 4.11: height above FWL using porous diagram

In above figure height above FWL was calculated by porous diagram = 50.04, initial water saturation 0.1667 and FWL = 1568m.

The different existing on calculating free water level consequent presence of a strange fluid in mercury injection method, which usually used in pore size distribution.

WFT data from well was available for this study. table show these data which were plotted in figure4.12.

4.2 Wireline formation tester

Table 4.2-1: WFT data

Depth, m	Pressure, psi	Fluid type
1,507.0		Oil
1,508.0		
1,509.0		
1,521.0	1994.40	
1,522.0	1995.80	
1,523.0		
1,528.5		
1,533.5	2006.30	
1,534.5	2007.70	
1,555.0	2028.00	
1,556.0	2029.70	
1,558.0	2032.00	
1,559.0	2034.00	
1,561.0	2036.80	
1,581.0	2064.70	
1,583.0	2067.40	
1,585.0	2070.30	
1,587.0	2073.20	
1,588.0	2074.60	

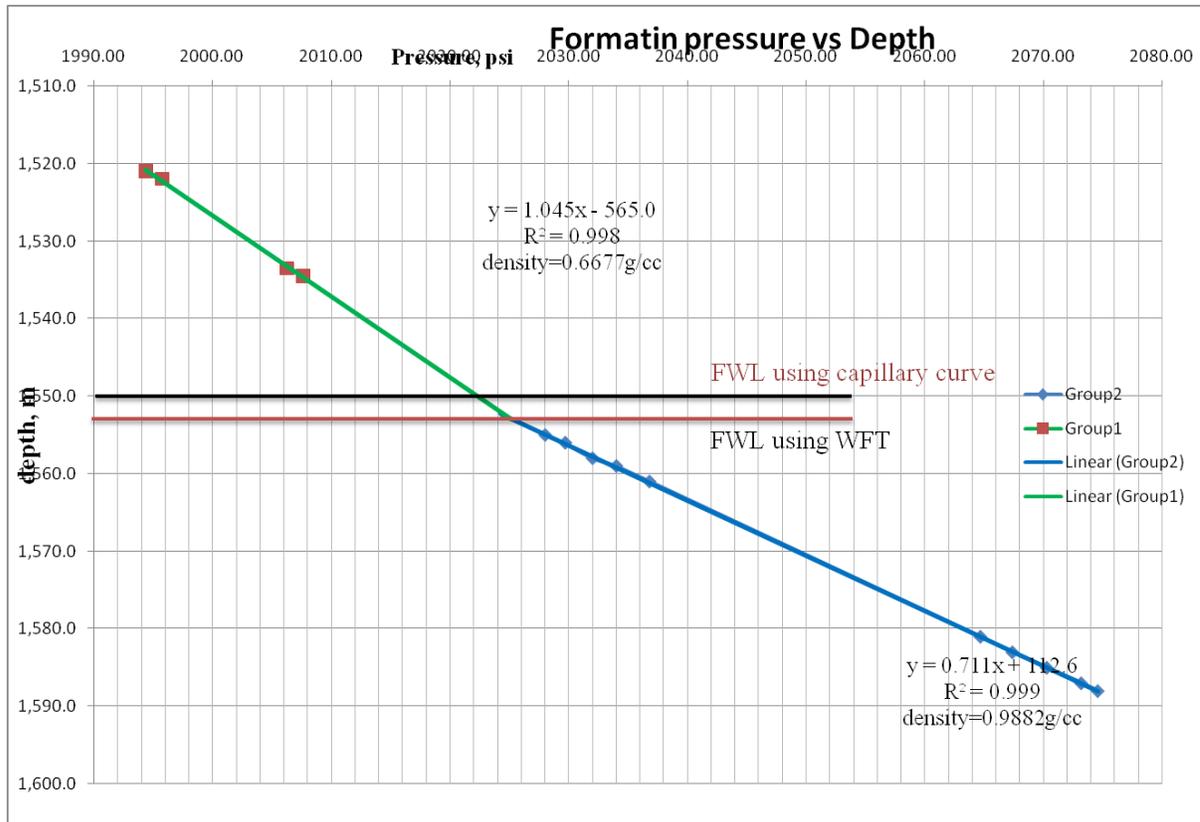


Figure 4.12: Pressure profile

From the above figure the intersect between the oil pressure gradient and the water pressure gradient result **Free Water Level** = 1553m.

The different on determine of free water level by wireline formation tester consequent presence of capillary pressure between drilling mud (water base mud) and fluid existing in the formation (oil).

Chapter 5: Conclusions and Recommendations

5.1 Conclusions

From this study conclusion can be summarized as follows:

- It has been found that the free water level obtained from WFT data and from capillary pressure data was at 1,553m, 1,550 m respectively. The difference between the two values shows the quantitative effect of capillary pressure on wire line formation testing measurements
- The concept of free fluid level, fluid contact, rock wettability, and pore fluid pressure are intimately related.
- The formation tester contact will generally be off from the actual FWL. In a water-wet medium, the contact will generally appear too high compared to the FWL, while in an oil-wet medium; it will generally appear too low compared to the FWL. In the latter case, the measured contact will indicate the highest producible water level.
- The effect capillary pressure will make the measured formation pressure either too high or too low depending on the specific wetting fluid-drilling mud formation fluid combination. This will result in shifted gradient lines, altered gradient slopes, or greater scatter.

5.2 Recommendations

- The study can be more accurate and effective if the other formation evaluation tools were used.
- Development of new software to convert from lap condition to reservoir condition by using J-function.
- To get more accurate result more sample and more wireline formation testing data are needed.

Appendix

Appendix A

Mercury injection calculation

Table 6.1: 1st sample using mercury injection

S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J
1	0.037052	0.028232	0.5	0.387662	0.295386	0.165	4.178349	3.183763
1	0.041657	0.031741	0.47	0.41097	0.313145	0.16	4.472142	3.407623
1	0.041728	0.031795	0.446	0.435624	0.331931	0.158	4.743548	3.614425
1	0.046757	0.035628	0.422	0.461837	0.351904	0.154	5.046975	3.845627
1	0.048741	0.037139	0.402	0.48897	0.372579	0.151	5.278425	4.021984
1	0.052213	0.039784	0.385	0.518583	0.395143	0.147	5.604523	4.27046
0.999	0.054763	0.041728	0.368	0.549613	0.418787	0.144	5.927008	4.516183
0.997	0.058872	0.044858	0.354	0.582839	0.444104	0.141	6.335003	4.827061
0.996	0.06206	0.047288	0.342	0.617341	0.470393	0.137	6.713172	5.115213
0.994	0.065815	0.050149	0.331	0.654676	0.498841	0.134	7.103384	5.412542
0.992	0.069003	0.052578	0.321	0.694278	0.529017	0.13	7.538371	5.743987
0.991	0.073608	0.056087	0.311	0.73636	0.561082	0.127	7.989368	6.087632
0.99	0.077717	0.059217	0.303	0.77212	0.594953	0.124	8.453401	6.44121
0.989	0.082109	0.062564	0.296	0.827253	0.63034	0.121	9.078109	6.917217
0.986	0.086926	0.066235	0.288	0.877128	0.668342	0.119	9.612916	7.324722
0.985	0.092027	0.070122	0.281	0.930403	0.708936	0.116	10.13129	7.719703
0.984	0.097411	0.074224	0.275	0.986229	0.751474	0.113	10.80622	8.233983
0.981	0.103433	0.078813	0.269	1.049847	0.799949	0.11	11.49731	8.76057
0.98	0.109738	0.083617	0.263	1.111482	0.846913	0.108	12.14838	9.256658
0.979	0.116185	0.088529	0.258	1.17751	0.897223	0.105	12.88573	9.818495
0.977	0.123057	0.093766	0.252	1.250409	0.95277	0.102	13.6607	10.409
0.975	0.130213	0.099218	0.247	1.325292	1.009828	0.1	14.45366	11.01321
0.973	0.137297	0.104616	0.242	1.405417	1.070881	0.098	15.44025	11.76495
0.971	0.145728	0.11104	0.237	1.489651	1.135065	0.095	16.26006	12.38962
0.969	0.154158	0.117463	0.232	1.57849	1.202757	0.093	17.36262	13.22974

Following pervious table

0.965	0.163368	0.124481	0.227	1.673777	1.275362	0.091	18.39319	14.015
0.962	0.173215	0.131984	0.223	1.777493	1.354391	0.089	19.44375	14.81549
0.956	0.183629	0.13992	0.218	1.882768	1.434607	0.087	20.75381	15.81371
0.948	0.194185	0.147963	0.214	1.99782	1.522272	0.085	21.92034	16.70257
0.929	0.205804	0.156816	0.209	2.118044	1.613879	0.083	23.36351	17.80222
0.89	0.217635	0.165831	0.206	2.197035	1.674068	0.081	24.62689	18.76487
0.849	0.230812	0.175871	0.202	2.344959	1.786781	0.079	26.20736	19.96914
0.821	0.244131	0.18602	0.198	2.517041	1.917901	0.077	27.70686	21.11171
0.785	0.258654	0.197086	0.194	2.67545	2.038604	0.076	29.46168	22.44882
0.746	0.273673	0.20853	0.191	2.844272	2.167241	0.074	31.17138	23.75155
0.709	0.289684	0.22073	0.185	3.059286	2.331074	0.072	33.01532	25.15658
0.671	0.306474	0.233523	0.182	3.218828	2.45264	0.07	35.06146	26.71567
0.63	0.324185	0.247018	0.177	3.473798	2.646919	0.068	37.11312	28.27896
0.584	0.344093	0.262187	0.173	3.730398	2.842439	0.066	39.37208	30.00021
0.538	0.364992	0.278112	0.169	3.907368	2.977284	0.064	41.80779	31.85614

Table 6-2: 2nd sample using mercury injection

S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J
1	0.036627	0.027869	0.587	0.364425	0.277291	0.245	4.196272	3.192943
1	0.041515	0.031589	0.563	0.387379	0.294756	0.241	4.425668	3.36749
1	0.041373	0.031481	0.542	0.410545	0.312384	0.236	4.655488	3.54236
1	0.046687	0.035524	0.525	0.43527	0.331197	0.231	4.987041	3.794638
1	0.047891	0.03644	0.507	0.46127	0.35098	0.227	5.276725	4.015059
0.996	0.052071	0.039621	0.491	0.488616	0.371788	0.222	5.63782	4.289816
0.995	0.053913	0.041022	0.475	0.518229	0.39432	0.218	6.000474	4.56576
0.991	0.058447	0.044472	0.463	0.549188	0.417877	0.213	6.385869	4.859007
0.989	0.061918	0.047114	0.45	0.582202	0.442997	0.209	6.723373	5.115813
0.987	0.065319	0.049701	0.439	0.616774	0.469303	0.204	7.186131	5.467926
0.984	0.068932	0.05245	0.429	0.654392	0.497927	0.2	7.504507	5.710178
0.982	0.073253	0.055739	0.419	0.694136	0.528168	0.195	8.062975	6.135117
0.98	0.077362	0.058865	0.408	0.735368	0.559541	0.191	8.515177	6.479197
0.977	0.081826	0.062261	0.399	0.78	0.593502	0.187	9.095395	6.920684
0.975	0.086785	0.066034	0.39	0.826332	0.628756	0.183	9.594992	7.300828
0.973	0.091744	0.069808	0.382	0.876845	0.667191	0.179	10.14822	7.721777
0.971	0.09727	0.074013	0.374	0.929978	0.70762	0.175	10.74785	8.178035
0.967	0.102796	0.078217	0.367	0.986016	0.75026	0.171	11.44085	8.705341
0.964	0.109455	0.083284	0.359	1.04921	0.798344	0.167	12.16779	9.258467
0.961	0.11576	0.088082	0.353	1.110916	0.845295	0.164	12.85817	9.783778
0.958	0.122845	0.093472	0.346	1.178856	0.896991	0.16	13.63477	10.37469
0.956	0.13	0.098917	0.34	1.249488	0.950735	0.157	14.48023	11.018
0.953	0.137226	0.104415	0.334	1.3243	1.007659	0.153	15.33015	11.66471
0.949	0.14509	0.110399	0.328	1.404283	1.068519	0.15	16.26977	12.37966
0.945	0.153804	0.117029	0.322	1.488872	1.132882	0.147	17.31196	13.17267
0.941	0.162943	0.123983	0.316	1.578136	1.200804	0.144	18.35395	13.96551
0.936	0.172719	0.131422	0.311	1.674627	1.274223	0.14	19.46968	14.81447
0.929	0.183134	0.139346	0.305	1.77721	1.352279	0.137	20.56586	15.64856
0.922	0.193831	0.147486	0.3	1.882698	1.432544	0.134	21.85934	16.63277
0.91	0.20545	0.156327	0.295	1.997041	1.519548	0.131	23.26511	17.70242
0.898	0.217068	0.165167	0.29	2.117264	1.611026	0.128	24.58835	18.70927
0.874	0.230458	0.175355	0.286	2.259662	1.719376	0.124	26.11236	19.86889

Following pervious table

0.839	0.243564	0.185328	0.283	2.395684	1.822875	0.121	27.68022	21.06188
0.836	0.243777	0.18549	0.279	2.528093	1.923625	0.117	29.33558	22.32144
0.804	0.258512	0.196702	0.276	2.703362	2.056988	0.114	31.17088	23.71792
0.8	0.258654	0.19681	0.271	2.868572	2.182696	0.11	33.00286	25.11187
0.773	0.273106	0.207807	0.266	3.120921	2.374708	0.106	35.074	26.6878
0.733	0.289117	0.219989	0.263	3.269837	2.488018	0.102	37.19799	28.30395
0.682	0.305978	0.232819	0.258	3.432496	2.611786	0.099	39.44859	30.01642
0.645	0.323689	0.246295	0.253	3.729193	2.837543	0.094	41.8153	31.81725
0.613	0.343809	0.261604	0.249	3.902125	2.969126			

Table 6.3: 3rd sample using mercury injection

S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J	S_w	Pc RES (o/w)	J
1	0.036627	0.05614	0.178	0.364425	0.558575	0.063	4.188338	6.419703
1	0.041515	0.063632	0.172	0.387379	0.593757	0.061	4.418016	6.771744
1	0.041373	0.063415	0.167	0.410545	0.629266	0.06	4.648262	7.124654
0.966	0.046687	0.071559	0.161	0.43527	0.667163	0.059	4.980098	7.633279
0.965	0.047891	0.073405	0.156	0.46127	0.707014	0.058	5.270136	8.077837
0.958	0.052071	0.079812	0.152	0.488616	0.748929	0.057	5.631586	8.631851
0.956	0.053913	0.082635	0.146	0.518229	0.794319	0.056	5.994594	9.188254
0.944	0.058447	0.089585	0.142	0.549188	0.841772	0.055	6.380414	9.779623
0.94	0.061918	0.094906	0.138	0.582202	0.892373	0.054	6.718202	10.29737
0.93	0.065319	0.100118	0.134	0.616774	0.945364	0.052	7.181313	11.00721
0.922	0.068932	0.105656	0.131	0.654392	1.003024	0.052	7.499973	11.49563
0.904	0.073253	0.11228	0.127	0.694136	1.063942	0.051	8.058866	12.35228
0.891	0.077362	0.118578	0.123	0.735368	1.12714	0.05	8.511422	13.04594
0.872	0.081826	0.125419	0.120	0.780000	1.19555	0.049	9.091924	13.93571
0.844	0.086785	0.13302	0.116	0.826332	1.266567	0.048	9.591875	14.70201
0.817	0.091744	0.140621	0.113	0.876845	1.34399	0.047	10.14538	15.55041
0.764	0.09727	0.149091	0.110	0.929978	1.42543	0.046	10.74537	16.47003
0.714	0.102796	0.157561	0.107	0.99048	1.518164	0.045	11.43865	17.53267
0.657	0.109455	0.167768	0.104	1.04921	1.608183	0.044	12.16587	18.64733
0.604	0.11576	0.177432	0.101	1.110916	1.702763	0.044	12.85654	19.70595
0.533	0.122845	0.188291	0.099	1.178856	1.806899	0.043	13.60409	20.85176
0.465	0.13	0.199258	0.096	1.249488	1.915161	0.042	14.47917	22.19304
0.422	0.137226	0.210334	0.093	1.3243	2.029829	0.041	15.32937	23.4962
0.382	0.14509	0.222388	0.091	1.404283	2.152425	0.041	16.2692	24.93672
0.351	0.153804	0.235744	0.089	1.488872	2.282078	0.040	17.31168	26.53459
0.327	0.162943	0.249752	0.087	1.578136	2.418899	0.039	18.35395	28.13213
0.306	0.172719	0.264737	0.085	1.674627	2.566795	0.038	19.46989	29.84261
0.289	0.183134	0.280699	0.081	1.77721	2.72403	0.037	20.56628	31.52311
0.274	0.193831	0.297096	0.080	1.882698	2.885717	0.037	21.86005	33.50614
0.261	0.20545	0.314904	0.078	1.997041	3.060978	0.036	23.2661	35.66128
0.250	0.217068	0.332713	0.076	2.117264	3.245251	0.035	24.58955	37.6898
0.239	0.230458	0.353236	0.076	2.248823	3.446898	0.034	26.11385	40.02618

Following pervious table

0.229	0.243564	0.373324	0.075	2.385057	3.655713	0.034	27.68192	42.42966
0.229	0.243777	0.37365	0.073	2.517678	3.858989	0.033	29.33756	44.96735
0.219	0.258512	0.396236	0.072	2.693232	4.128069	0.032	31.17315	47.78086
0.219	0.258654	0.396454	0.071	2.858725	4.38173	0.030	33.00541	50.58926
0.211	0.273106	0.418605	0.069	3.111428	4.769062	0.029	35.07683	53.76425
0.204	0.289117	0.443146	0.068	3.260556	4.997639	0.029	37.19714	57.01417
0.197	0.305978	0.46899	0.066	3.423569	5.247499	0.027	39.45192	60.47019
0.191	0.323689	0.496137	0.065	3.720621	5.702807	0.025	41.81898	64.09832
0.184	0.343809	0.526976	0.064	3.893907	5.968413	-----	-----	-----

Table 6.4: Determine height above FWL using mercury injection

S_w	J	P_c	H
1.000	0.0840000	0.08743029	0.19184178
0.900	0.10197015	0.106134286	0.23288257
0.800	0.12664665	0.131818494	0.28923951
0.700	0.1619194	0.168531671	0.36979651
0.600	0.21502105	0.223801823	0.49107169
0.500	0.30072842	0.313009207	0.68681282
0.400	0.45340771	0.471923427	1.03550647
0.300	0.76979693	0.80123297	1.7580859
0.200	1.62324508	1.689533194	3.707217
0.100	5.81138016	6.048698266	13.2722086
0.061	14.4302013	15.0194844	32.9561373

Appendix B

Porous diagram Calculation

Table 6.5: Samples using porous diagram

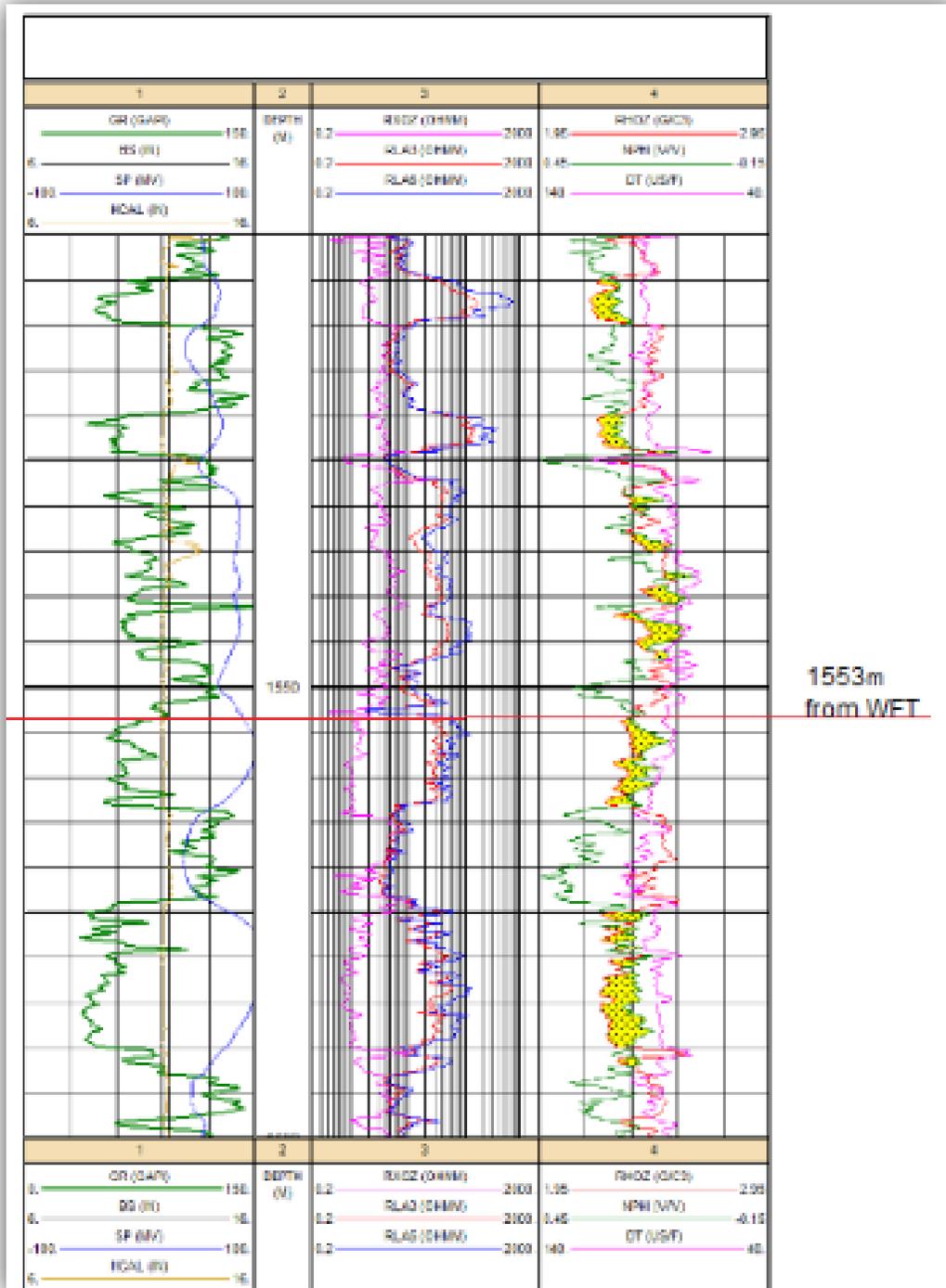
S_w	Pc RES(O/W)	J
1.000	0	0
0.299	0.897619048	1.071515576
0.241	1.795238095	2.143031153
0.241	3.59047619	4.286062305
0.241	8.976190476	10.71515576
0.232	17.95238095	21.43031153
0.232	44.88095238	53.57577881
0.597	0.897619048	1.071515576
0.401	1.795238095	2.143031153
0.381	3.59047619	4.286062305
0.355	8.976190476	10.71515576
0.329	17.95238095	21.43031153
0.313	44.88095238	53.57577881

Table 6.6: Determine height above FWL using porous diagram

S_w	J	Pc	H
1	0.529	0.44314846	0.972368
0.9	0.66699434	0.55874767	1.226018
0.8	0.86428644	0.72402118	1.588666
0.7	1.15941785	0.97125564	2.131154
0.6	1.62750721	1.36337866	2.99156
0.5	2.43064572	2.03617562	4.467829
0.4	3.97121766	3.32672776	7.299591
0.3	7.47805942	6.2644433	13.7456
0.2725	9.23951889	7.74003507	16.98338

Appendix C

Figure 6.1: Logging data interpretation



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