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Improve Estimation for Fluid Contacts Using Excess Pressure

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الاستهلال

قال تعالى:

{... وَقُلْ رَّبِّ زِدْنِي عِلْمًا }

صدق الله العظيم

DEDICATION

To our lovely mothers whom we bare this success and never

Slept in night to see us on the top.

To our fathers that helped us through the way by giving us all

We need of advices, care and support through all the things we

Have been through in our life.

To our doctors and lecturers that help us through our studies

And spent a lot of their times to supply us with knowledge and

Work hard to graduate us.

To our supervisor **ABDULLAH ABDULJABBAR** how supply us

With all we need of knowledge.

To our brothers, sisters and family class mates

To our dear friends who supported us in these journey

To everyone who helped us without forgetting someone.

Thanks all you

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Thanks full and appreciation of Allah as always before and after

Without the encouragement and support of some people this these would have not

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Furthermore we want to thanks the sudan university of science and technology with

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ABSTRACT

Positions of initial fluid contacts and free water level (FWL) are critical for field reserve estimates and for field development. Typically, the position of fluid contacts are first determined within control wells and then extrapolated to other parts of the field.

Methods for determining initial fluid contact free water level (FWL) include fluid sampling methods, saturation estimation from wireline logs, estimation from conventional and sidewall cores, and pressure methods.

In this research pressure methods were used by improve the interpretation of wireline pressure data by using the concept of **Excess Pressure**.

Wireline pressure data were collected from well **N-12** which locate in Neem oilfield in block 4 Sudan to enhance estimation of free water level (FWL) and the oil water contact(OWC), and to correlate with logging data to insurance interpretation.

Interactive Petro-physics (IP) software is used to well N-12 to determination of zones of interest and petrophysical properties calculation; while **Microsoft excel** is used to plot graphs.

It has been found that there are six zones of interest, and pressure gradient values indicate the above five zones contain moveable hydrocarbon (gas or oil) and the underlying zone (zone 6) contains water.

The free water level (FWL) obtained from wireline formation testing (WFT) has been found at depth 1875m (6151.575ft).Then compare the position of (FWL) to insurance interpretation.

التجريد

تحديد نقطة التماس بين الموائع وتحديد مستوي الماء الحر داخل المكمن مهمة لتقيم الاحتياطي الهيدروكربوني وتطوير الحقل.

هنالك العديد من الطرق المستخدمة في تحديد مستوي الماء الحر ونقاط التماس بين الموائع ، تشمل : طريقة أخذ عينات من الموائع لاختبارات الضغط والحجم والحرارة، وطريقة تقدير التشبع باستخدام تسجيلات الآبار، وطريقة عينات اللباب وكذلك بيانات الضغط المأخوذة من اختبارات الآبار.

في هذا البحث تم استخدام طريقة بيانات الضغط بطرقة تحليل متطورة تسمى (Excess Pressure) .

بيانات الضغط تم جلبها من حقل نيم النفطي التي تقع في مربع 4 في غرب السودان من البئر N-12 لتحسين

تقدير موقع مستوى الماء الحر FWL وكذلك نقاط التماس بين الموائع ، ومقارنتها مع نتائج تسجيلات الآبار.

تم استخدام برنامج (IP) لتحديد الطبقات المستهدفة وكذلك معرفة الخواص الفيزيائية لها. كما تم استخدام (Microsoft excel) لعمل الرسومات البيانية.

أظهرت عمليات التحليل 6 مناطق مستهدفة، المناطق الخمسة العليا تحتوي على هيدروكربون (زيت او غاز) والمنطقة السادسة تحتوي على ماء كما أظهرت عمليات تدرج الضغط.

وجد ان مستوى الماء الحر المتحصل عليه من بيانات الضغط يقع عند العمق 1875m وتمت مقارنته بتسجيلات الآبار.

1 Chapter One: Introduction

1.1 General Introduction

Positions of initial fluid contacts are critical for field reserve estimates and for field development. Typically, the position of fluid contacts are first determined within control wells and then extrapolated to other parts of the field. Definitions of fluid contacts are based on comparison to capillary pressure curves. The free water level is the highest elevation at which the pressure of the hydrocarbon phase is the same as that of water. The hydrocarbon-water (oil-water or gas-water) contact is the lowest elevation at which mobile hydrocarbons occur. The transition zone is the elevation range in which water is coproduced with hydrocarbons. The gas-oil contact is the elevation above which gas is the produced hydrocarbon phase.

Methods for determining initial fluid contact include fluid sampling methods, saturation estimation from wireline logs, estimation from conventional and sidewall cores, and pressure methods. Once initial fluid contact elevations in control wells are determined, the contacts in other parts of the reservoir can be estimated. Initial fluid contacts within most reservoirs having a high degree of continuity are almost horizontal, so the reservoir fluid contact elevations are those of the control wells.

Modern wireline pressure data can have resolution and reproducibility sufficient to detect small fluid-density changes and pressure barriers, yet these features are commonly overlooked on conventional pressure-depth plots. The large pressure variation caused by weight of subsurface fluids hides these subtle features.

Excess pressure is the pressure left after subtracting the weight of a fluid from the total pressure. This concept is applied to wireline pressure data to remove effects of weight and emphasize subtle pressure differences caused by density variations and pressure barriers.

Pressure-depth plots have been used for the last quarter century to evaluate fluid density, fluid contacts, and pressure compartmentalization from wireline pressure surveys (Pelissier- Combescure et al., 1979).

This Project uses a new interpretation technique based on the concept of excess pressure. Data are transformed to remove the effects of the weight of the static fluid;

thereby, small pressure differences can be visualized. This technique enhances the measurement of fluid densities and resolves small density changes and pressure barriers that are not likely to be recognized on standard pressure-depth plots Much of the pressure variations in pressure-depth plots are caused by the weight of the fluids themselves. By removing effects of the weight of one of the fluids on pressure, small pressure differences caused by density variations and pressure barriers can be enhanced. This approach is referred to as the ‘‘excess-pressure’’ method (Brown and Loucks, 2000).

Excess pressure is calculated froman assumed fluid density, gauge depth, andmeasured pressure. Excess pressure is the difference between the measured pressure and the pressure expected from the weight of a fluid between the datum and the depth of pressure measurement.

1.2 Problem Statement:

Defining the depths of the free water level (FWL), and fluid contacts oil/water contact (OWC) is essential for volumetric calculations and important for detailed petrophysical calculations so there are challenges faces this work: density differences, and Low salinity (fresh) water from resistivity measurements cannot certainty locate fluids contacts.

1.3 Project Objectives:

The main objectives of this project is to:

- Enhance the estimation offree water level**FWL** and oil water contact **OWC**by using excess pressure method.
- Correlate the results with well logging data.

1.4 Introduction to case study:

In the table below some information related to the studied area. The work has been done in block 4 (Neem oilfield).

Table 1: Information about case study area

Country	Blocks	Consortium	Main Fields	Shareholders
Sudan	2 and 4	Greater Nile Petroleum Operating Company (GNPOC)	Heglig/Panthou Bamboo Diffra Neem	CNPC International (Nile): 40% Petronas: 30% ONGC: 25% Sudapet: 5%

The Neem oilfield is in oil block 4 run by the Greater Nile Petroleum Operating Company(GNPOC). It is in South Kordofan, an area of conflict between Sudan's north and south whosigned a peace deal in January 2005 to end Africa's longest civil war.

Figure 1-1Shows Some blocks in Sudan including the case study area(Block 4 [Neem oilfield]).

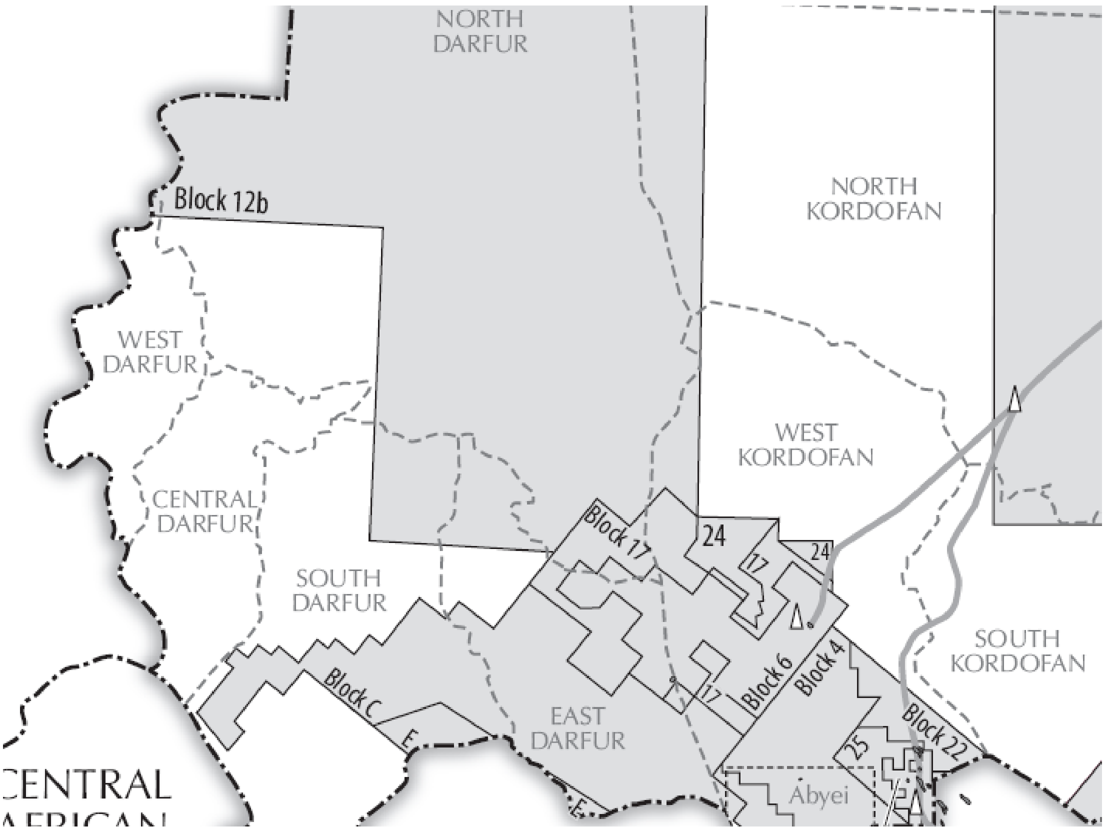

Figure 1-1: Some of oil blocks in Sudan (Aug 2, 2006 (KHARTOUM)**)**

The main producing formation in Neem oilfield is Bentiuformation (light oil):

1.4.1 Bentiu formation:

Bentiu Formation is the main oil-bearing unit in the study area, with average thickness of 317 m. The Bentiu Sandstone consists of a series of sandstones interbedded with claystone. Sandstone are medium to coarse grained and less consolidated than the overlying Formations, generally deposited in a braided stream environment with high Rw.

2 Chapter Two: Background and Literature Review

2.1 Fundamental of Rock Properties

The material of which a petroleum reservoir rock may be composed can rangefrom very loose and unconsolidated sand to a very hard anddense sandstone , limestone , or dolomite. The grains may be bondedtogether with a number of materials, the most common of which are silica, calcite, or clay. 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 oncores from the reservoir to be evaluated. The cores are removed from thereservoir 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. These are:

Routine core analysis tests

• Porosity

• Permeability

• Saturation

Special tests

• Overburden pressure

• Capillary pressure

• Relative permeability

• Wettability

• Surface and interfacial tension

The above rock property data are essential for reservoir engineering calculations as they directly affect both the quantity and the distribution of hydrocarbons and, when combined with fluid properties, control the flow of the existing phases (i.e., gas, oil, and water) within the reservoir.

2.1.1 Porosity:

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is theratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically by the following generalized relationship:

$$\phi=\frac{pore\ volume}{bulk\ volume} \quad \mathbf{2.1}$$

Where:

ϕ=porosity

As the sediments were deposited and the rocks were being formed during past geological times , some void spaces that developed became isolated

from the other void spaces by excessive cementation. Thus, 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

• Effective porosity

Absolute porosity

The absolute porosity is defined as the ratio of the total pore space in the rock to that of the bulk volume. A rock may have considerable absolute porosity and yet have no conductivity to fluid for lack of pore

ϕ_a =pore volume/bulk volume

interconnection. The absolute porosity is generally expressed mathematically

by the following relationships:

$$\phi_a = \frac{total\ pore\ volume}{bulk\ volume} \quad \mathbf{2.3}$$

Or

$$\phi_a = \frac{bulk\ volume - grain\ volume}{bulk\ volume} \quad \mathbf{2.4}$$

Where ϕ_a = absolute porosity

Effective porosity

The effective porosity is the percentage of interconnectedpore space
with respect to the bulk volume, or

$$\phi = \frac{\textit{interconnected pore volume}}{\textit{bulk volume}} \quad 2.5$$

Where ϕ= effective porosity

The effective porosity 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 induced. The originalporosity is that developed in the deposition of the material, while inducedporosity is that developed by some geologic process subsequent to deposition of the rock. The intergranular porosity of sandstones and the intercrystalline and oolitic porosity of some limestones typify original porosity. Induced porosity is typified by fracture development as found in shales and limestones and by the slugs or solution cavities commonly found in limestones. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is included. For direct quantitative measurement of porosity, reliance must be placed on formation samples obtained by coring. Since effective porosity is the porosity value of interest to the petroleum engineer, particular attention should be paid to the methods used the bulk volume (Tariq Ahmed ,2000) .

2.1.2 Saturation:

Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$\textbf{fluid saturation} = \frac{\textit{total volume of the fluid}}{\textit{pore volume}} \quad 1.6$$

Applying the above mathematical concept of saturation to each reservoir
fluid gives :

$$\mathbf{So} = \frac{volume\ of\ oil}{pore\ volume} \quad \mathbf{2.7}$$

$$\mathbf{Sg} = \frac{volume\ of\ gas}{pore\ volume} \quad \mathbf{2.8}$$

$$\mathbf{Sw} = \frac{volume\ of\ water}{pore\ volume} \quad \mathbf{2.9}$$

Where

So = oil saturation

Sg = gas saturation

Sw = water saturation

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 percent. By definition, the sum of the saturations is 100%, therefore

Sg + So + Sw = 1.0 2.10

The fluids in most reservoirs are believed to have reached a state of equilibrium and, therefore, will have become separated according to theirdensity, i.e., oil overlain by gas and underlain by water. In addition to thebottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as *capillary forces* because they are important only in pore spaces of capillary size. Connate (interstitial) water saturation Swc is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table. Another particular phase saturation of interest is called the critical saturation and it is associated with each reservoir fluid. The definition and the significance of the critical saturation for each phase is described below.

Critical oil saturation, Soc

For the oil phase to flow, the saturation of the oil must exceed a certainvalue which is termed critical oil saturation. At this particular saturation,the oil remains in the pores and, for all practical purposes, will not flow.

Residual oil saturation, Sor

During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation,*Sor*. The term residual saturation is usually associated with the nonwetting phase when it is being displaced by a wetting phase.

Movable oil saturation, Som

Movable oil saturation Som is another saturation of interest and is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

Som = 1 - Swc–Soc2.11

Where

Swc = connate water saturation

Soc = critical oil saturation

Critical gas saturation, Sgc

As the reservoir pressure declines below the bubble-point pressure, gas
evolves from the oil phase and consequently the saturation of the gas increases as the reservoir pressure declines. The gas phase remains immobile until its saturation exceeds a certain saturation, called critical
gas saturation,above which gas begins to move.

Critical water saturation, Swc

The critical water saturation, connate water saturation, and irreducible water saturation are extensively used interchangeably to define the maximum water saturation at which the water phase will remain immobile.

Average Saturation

Proper averaging of saturation data requires that the saturation values be weighted by both the interval thicknessand interval porosity(Tariq Ahmed ,2000).

Thus, all saturation values are based on pore volume and not on the gross reservoir volume.

2.1.3 Permeability:

In addition to being porous, a reservoir rock must have the ability to allow petroleum fluids to flow through its interconnected pores. The rock's ability to conduct fluids is termed as permeability. This indicates that non-porous rocks have no permeability. The permeability of a rock depends on its effective porosity, consequently, it is affected by the rock grain size, grain shape, grain size distribution (sorting), grain packing, and the degree of consolidation and cementation. French engineer Henry Darcy developed a fluid flow equation that since has become one of the standard mathematical tools of the petroleum engineer**.** This equation is expressed in differential form as follows :

$$\mathbf{u} = \frac{q}{A} = \frac{K}{\mu}\frac{dp}{dl} \qquad \mathbf{2.12}$$

where:

u = fluid velocity, cm/s.

q = flow rate cm3/s.

k = permeability of the porous rock, Darcy (0.986923 pm').

A= cross-sectional area of the rock, cm'.

μ= viscosity of the fluid, centipoises (cP).

1 = length of the rock sample, cm.

$\frac{dp}{dl}$= pressure gradient in the direction of the flow, atm/cm.

The permeability, K, in Equation is termed the "absolute" permeability if the rock is 100% saturated with a single fluid (or phase), such as oil, gas, or water. In presence of more than one fluid, permeability is called the "effective" permeability (Ko**,** Kg, or Kw, being oil, gas, or water effective permeability respectively). The sum of the effective permeabilities of all the phases will always be less than the absolute permeability.

2.1.4 Wettability:

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids.

The tendency of a liquid to spread over the surface of a solid is an indication of the *wetting* characteristics of the liquid for the solid. This spreading tendency can be expressed more conveniently by measuring the angle of contact at the *liquid-solid* surface. This angle, which is always measured through the liquid to the solid, is called the contact angle Θ.

The contact angle Θhas achieved significance as a measure of wettability. Complete wettability would be evidenced by a zero contact angle, and complete nonwetting would be evidenced by a contact angle of 180°. The wettability of reservoir rocks to the fluids is important in that the distribution of the fluids in the porous media is a function of wettability. Because of the attractive forces, the wetting phase tends to occupy the smaller pores of the rock and the nonwetting phase occupies the more open channels.

Displacement pressure (PD) is the threshold or entry capillary pressure needed for the non-wetting phase to displace the wetting phase from the largest pores.

The Free water level (FWL) in a reservoir is the level at which the oil-water capillary pressure vanishes. It is the oil water interface that would exist at equilibrium in an observation borehole, free of capillary effects, if it were to be drilled in the porous medium and filled with oil and water.

The Oil-water contact (OWC) 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.

The residual oil saturation (Sor) is the oil saturation level above which the oil starts to be moveable.

The connate or irreducible water saturation (Swc) is the water saturation level below which the water becomes immovable.

Drainage is a process in which the wetting phase saturation decreases and the non-wetting phase saturation increases.

Imbibition is process in which the wetting phase saturation increases and the non-wetting phase saturation decreases.

Supercharging is a phenomenon that leads to measurement of a formation pressure that is higher than actual, leading to scattered pressure profiles or to altered gradients. The degree of supercharging is generally inversely related to permeability (H.Elshahawi, 1999).Supercharging results from leakage of mud filtrate through the filter cake. All filter cakes that developed from water-based muds are permeable; thus, filtrate from overbalanced mud leaks into the formation. If the filter cake has high permeability or if the formation has low permeability, leakage into the formation is faster than dispersion into the formation. Pressure rises above the formation pressure near the borehole wall. The probe measures pressure at the borehole wall; thus, tests have high pressures unrepresentative of the formation. All wireline pressure tests in water-based muds are supercharged because filtration through the filter cake always occurs. Under good logging conditions, supercharging is too small to measure.

2.2 Uses of pressure Measurements:

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

- In a virgin reservoir provide a wealth of information about that reservoir.
- They are important in supplementing data unattainable from seismic surveys, cores, conventional logs, and geological studies, hence helping to develop a static model of the reservoir.
- The distribution of formation pressure across a hydrocarbon reservoir and across its associated sedimentary basin provides invaluable insights into their history, structure, as well as formation and fluid characteristics.
- Pressure gradients identify producible fluid by determining fluid densities and locating fluid contacts.
- For fluid identification and for the location of reservoir fluid contacts.
- In the more complex case of a developed reservoir, formation pressures can also yield a lot of information.
- Pressure drop can be used to further our understanding of the reservoir’s structure by providing a way of zoning the reservoir into different layers.

2.3 Pressure Analysis Methodology:

The wireline pressures discussed in this project are ‘‘pretest’’ pressures; that is, the static formation pressures are collected before wireline sampling. Data are collected in the following manner (Pelissier-Combescure et al., 1979). The tool probe is pressed through the filter cake to the borehole wall. A small volume of fluid is withdrawnFromthe formation, and thus, the pressure drops (drawdown). Pressure then builds as fluids in the formation flow toward the borehole (buildup). Drawdown volume is normally so small that the pressure stabilizes within a few minutes. In good tests, pressure stabilizes at the formation pressure and the pretest ends. The mud pressure

at the test depth is recorded prior to setting the probe and after withdrawal of the probe. These are reported as hydrostatic or mud pressures. The other reported pretest result is the drawdown mobility (formation permeability/filtrate viscosity). It is calculated from the pressure drop during drawdown.

The most commonly used wireline pressure–interpretation technique is the pressure-depth diagram, a plot of stabilized formation pressure against true vertical depth. If the total pressure variation is large, pressure-depth diagrams do not have resolution sufficient to take advantage of the resolution of modern wireline pressure gauges. For example, the pressure data in Figure 2-1 appear to be of quite high quality (low scatter), but the fluid contact is hard to identify, even where contact elevation is identified. Water and oil in this example have a relatively small density difference, and thus, the pressure-depth trends of the two fluids are nearly parallel. One way to visualize small density differences is to expand the pressure scale. The slope difference is greater, but the contact may still be difficult to recognize. In addition, scale expansion increases the size of the diagram, and large diagrams are cumbersome.

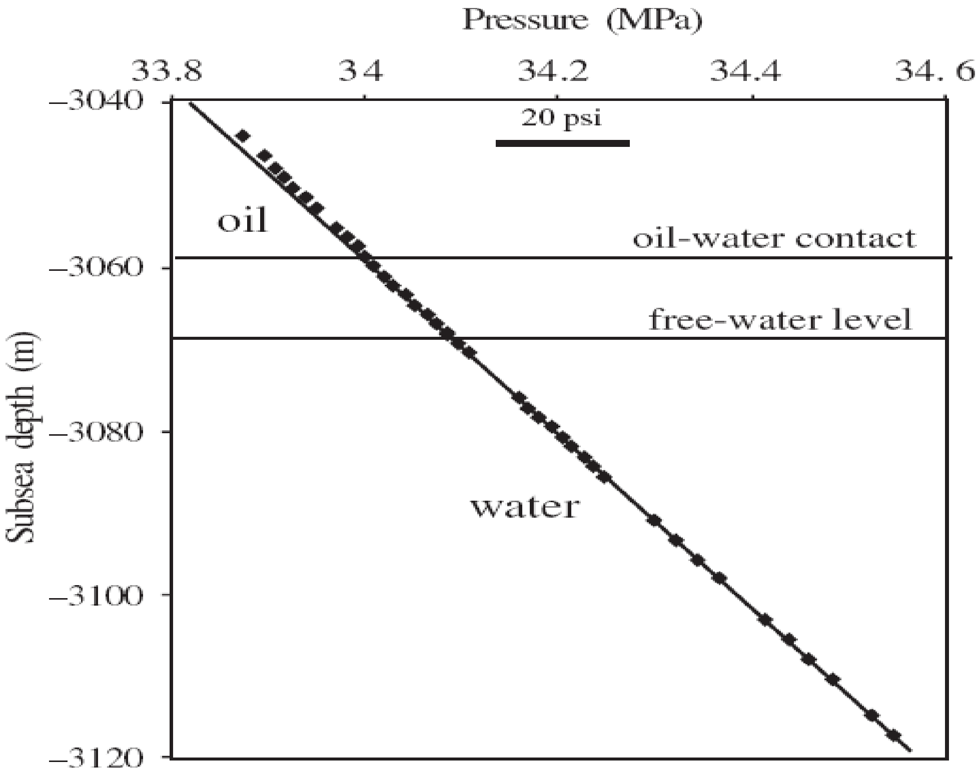

Figure 2-1: Conventional pressure vs depth diagram(Dewan, 1983)

2.3.1 Data Quality Control:

Pressure-measurement problems, supercharging, or depth errors may cause bad data. In most cases, bad data cannot be corrected. Thus, the best strategy is the identification of bad or suspect data and its elimination from the data set. The data normally supplied to the geologist is a table of summary pretest formation pressures, their depths, hydrostatic pressures, and drawdown mobilities (formation permeability/fluid viscosity).

Quality must be assessed from the transient pressure data and other data available on the pressure- test logs.

2.3.2 Depth Errors:

A depth error of 0.3 m will result in approximately 3 kPa (0.4 psi) excess-pressure error in water-bearing sections; thus, depth errors decrease excess-pressure data quality. Depths must be adjusted to true vertical depth for proper analysis. If the depth datum is adjusted during the pressure logging run, pressure tests before and after depth adjustment should be compared to see if there is a systematic pressure difference caused by the depth adjustment. Pulling stuck tools is likely to stretch the cable, and logging runs with tool sticking may have higher scatter than other data. Within-well depth errors are difficult to detect or correct. Theoretically, the mud pressure can be usedto correct the depth, but this has not proved useful unless depth errors are great.

2.3.3 Barrier Detection:

Flow barriers have prevented formation fluids from reaching equilibrium over geologic time. Because the fluid has not reached equilibrium, a potential difference exists on opposite sides of the barrier. This pressure potential means that formation fluid would flow if the barrier were removed. Variation in potential can easily be seen when carefully analyzing gradients and provides a means of identifying flow barriers.

Gradients may not be continuous through what is thought to be a single reservoir. In these instances, two or more similar of identical gradients can be identified; however, they can have a potential difference because of an existing flow barrier. Vertical flow barriers can be identified by this potential.

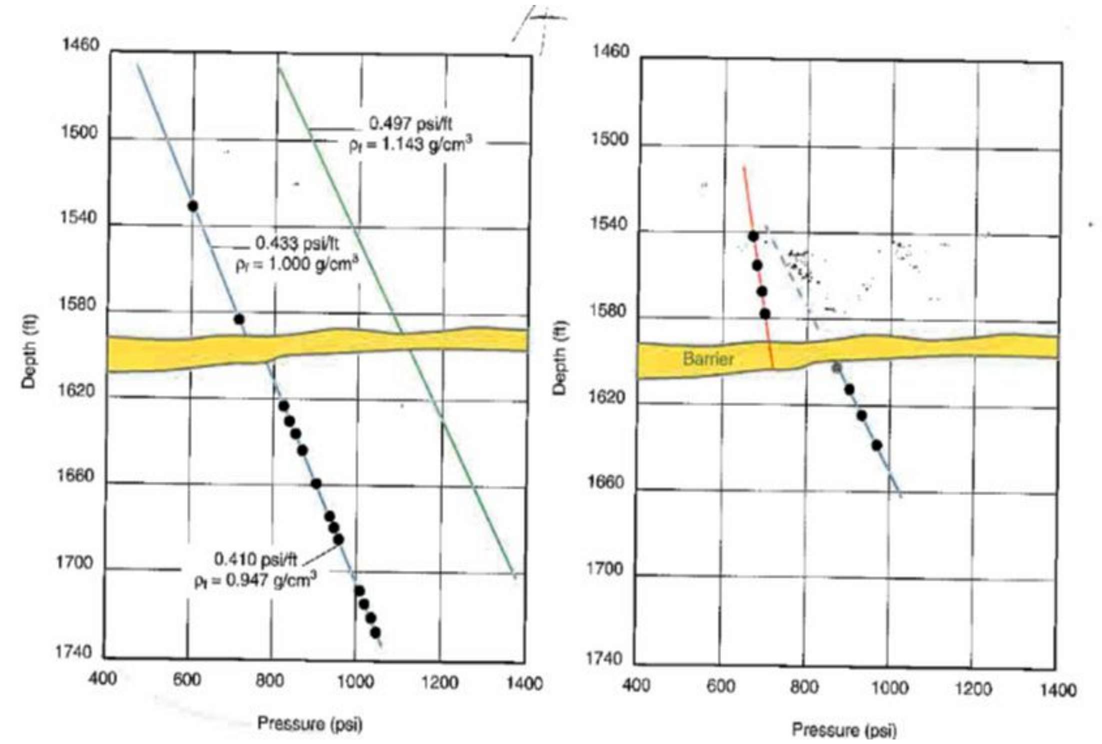

Figure 2-2:Vertical flow barriers detected because of pressure potentials(Karl.A.Lehne**).**

2.4 Excess pressure methodology:

2.4.1 Excess pressure Definition:

Much of the pressure variations in pressure-depth plots are caused by the weight of the fluids themselves. By removing effects of the weight of one of the fluids on pressure, small pressure differences caused by density variations and pressure barriers can be enhanced. This approach is referred to as the ‘‘excess-pressure’’ method (Brown and Loucks, 2000). Excess-pressure estimationis a common technique used elsewhere to analyze basinscale water flow and geopressure development (e.g., overpressure of Mann and Mackenzie, 1990). In hydrologic applications, freshwater or native-water density is used for excess-pressure calculation. For wireline pressure analysis, the density of any fluid in the reservoir is used.

Excess pressure is calculated froman assumed fluid density, gauge depth, and measured pressure. Excess pressure is the difference between the measured pressure and the pressure expected from the weight of a fluid between the datum and the depth of pressure measurement (Figure 2.3A). A single static fluid having constant density and free communication with itself (no barriers) has the same excess pressure at all elevations if density is chosen correctly (Figure 2.3B). Excess pressure is constant because fluid potential is uniform.

Excess pressure can be calculated using any datum. The magnitude of the excess pressure has less meaning than excess-pressure differences calculated using the same datum and fluid density. Excess pressure is easiest to interpret if the chosen fluid density is the dominant reservoir fluid density.

2.4.2 Construction of excess pressure plots:

Excess-pressure plots are constructed by identifying the density that equalizes excess pressure of thefluid of interest at all depths. Start by choosing a depth interval in the pressure survey that has a single fluid and no potential sealing lithologies. Excess pressures are calculated and plotted against depth using an arbitrary fluid density. If the excess-pressure-vs.-depth trend is rotated clockwise from vertical, the chosen density is too high and a lower density value is substituted. The assumed density is iterated until excess-pressure variance is minimized and the excess-pressure trend is vertical.

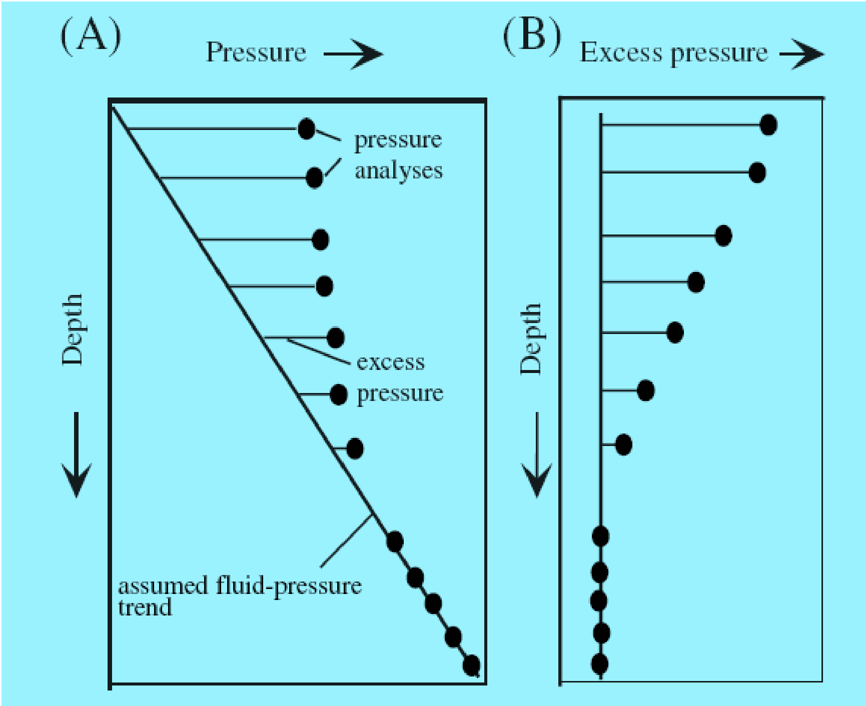

Figure 2-3: Excess pressure concept (Brown and Lucks, 2000**)**

2.5 Pressure Measurement errors:

Pressure-measurement problems have been recognized since the introduction of multiple-testing tools (e.g., Dewan, 1983). Traditional criteria identify data with tens to hundreds of psi errors. These buildup criteria have been modified to detect problems in the psi range desired for high-resolution pressure analysis.

Pressure builds slowly in low-permeability rocks. Where reservoir permeability is very low, tight tests are identified and the tests are aborted. Low-permeability tests that approach static pressure are sometimes terminated prematurely to save rig time and prevent tool sticking. Final pressures of these tests are not stabilized. Static pressure can be determined by extrapolating pressure data using a Horner plot or spherical-flow plot (see Dewan, 1983, for methods). Extrapolated pressures of incomplete tests should be used with caution.Most tests with incomplete buildup occur in low-permeability rockwhere supercharging is likely. Early test terminationoffsets some of the supercharging effects.Where theprobe is completely plugged or the sealis completely lost, major pressure differences from reservoirpressure are quickly noted and the test is abortedand noted on the summary table. In some tests, probe-sealleakage and probe plugging are minor and the testis completed. Leakage and periodic plugging may occur during the entire buildup period or during the early or late parts of the buildup. Pressure spikes or drops on the buildup curve identify subtle seal leakage.

2.6 Limits to Barrier and Fluid Contact Identification:

The excess-pressure scale can be expanded sufficiently to display small, random excess-pressure variation. Random pressure variations will cause excess-pressure configurations similar to barriers or fluid contacts if few tests are available over the reservoir interval.

The confidence in the slope of a data trend or change of the mean between two populations is controlled on the number of data points, the data variance, and (for confidence of slope estimate) the depth range over which the slope is measured. Increasing the number of valid tests and test quality control increases interpretation confidence.

Possible barriers should always be verified by integrating pressure analysis with other data. A pressurebarrier must be associated with some lithological feature laterally extensive enough to isolate parts of the reservoir. In most reservoirs, this is an evaporite bed,mudrock bed, or clay-rich fault zone in the depth rangeof the expected seal. If a small pressure offset is associatedwith the same stratigraphic horizon in nearbywells, then the barrier is probably valid.

2.7 Wireline Formation Testing:

There are a range of wireline formation testing tools now available, such as the Repeat Formation Tester(*RFT*), Repeat FormationSampler(*RFS*), the FormationMulti-Tester(*FMT*) and the new tool of schlumberger Modular FormationDynamics Tester (*MDT*). These tools are capable of taking multiple samples of fluids and pressure measurements in the borehole without withdrawal. These testers can mix the fluids sampled from several *settings* in one chamber, or take two separate samples and keep them separate. Fluids can be maintained at high pressure, which is important in some volatile oils as a sudden pressure drop causes a change in the composition of the oil. Time is saved by the tools incorporating a pre-test facility, where the seal between the probe and the rock formation is tested and an adequate flow of fluids for sampling is checked. If either of these is not the case, the tool can be reset at another depth for another try. This facility also enables the first part of the sample (mud filtrate) to be stored separately from the latter part of the fluid sample (reservoir fluids), or enable the first part to be ignored, so that the sample reliably samples only the reservoir fluid. The tools can cope with consolidated and unconsolidated formations, and provide very accurate fluid pressure readings. The tools also require very little timebetween runs for re-dressingthe tool, i.e., unloading the sampled fluids and preparation for the next run .

The tool can be customized efficiently assembled on-site to meet exact requirement depending on the needs of a particular well evaluation .It esigned to take several measurements and fluid samples during one trip in the well. The configuration, which extend the capabilities of exiting single-probe testers provide a basic tool to which additional modules and therefore capabilities can be added.

Applications of WFT:

1-Formation pressure measurements and Fluid contacts identifications.

2-Formation fluid sampling.

3-Permeability measurement.

4-Permeability anisotropy measurement.

5-Mini-Drillstem test (*DST*) and productivity assessment.

6-In-situ stress and minifrac testing.

2.8 Literature Review

This part provides a highlight and general over view of previous works related to formation evaluation based in wireline formation tester to determine OWC and FWL that have been conducted by some researchers :

E.C.Okolie et al (2007) estimated the high of oil –Water contact using capillary pressure, for different rock types form some Niger Delta reservoir, data obtained from oil displacing brine (drainage) capillary pressure tests using refined oil as simulated brine formation or reservoir fluid on various rock samples were used to illustrate the basic capillary behavior of ten hydrocarbon reservoirs, results, prominent plateau at a very low pressure indicative of a good reservoir.

A particular difficulty in evaluating hydrocarbon water contacts in most reservoirs in Niger Delta is as a result of increased shaliness which is manifested in small pore throats as high capillary pressure and high water saturation. Fluid contacts are represented as depth ranges in well test intervals until data from several reservoirs are correlated due to gradient extrapolation uficertainties in fluid properties.

Jarotsetyowiyoto et al (2006) estimated OWC and Hydrocarbon saturation by using well logging data ,data used in these study from well ~~JS 35~~, the study has been done by qualitative and quantitative analysis, qualitative analysis include determination of porous zone, sand and shale base line, water bearing formation and hydrocarbon depletion zone, quantitative analysis include calculation of formation temperature, mud filtrate resistivity, shale volume, porosity, and water and hydrocarbon saturation, porosity value are obtained from density log and then corrected by shale volume and hydrocarbon fluid contain, hydrocarbon saturation is estimated from water saturation which are calculated from true resistivity(Rt), shale volume(Vsh), and corrected porosity parameters. The lithology of well between sandstone and clay stone, the hydrocarbon is trapped in ten porous zones that have reservoir thickness vary between 11-90 feet, oil water contact occurred in 2229 feet, the highest hydrocarbon saturation of 85,7%,and temperature 157,4 F, the average porosity range from 21-32.3

H.Elshahawi and K.Fathy and S. Hiekal in 1999 explores the effect of capillary pressure and formation wettability on formation tester measurement as manifested in fluid level and/or gradient changes and investigates ways of attempting to correct for these effects.

3 Chapter Three: WFT& Excess Pressure Methodology

3.1 Problem description:

Defining the depths of the free water level (FWL), and fluid contacts oil/water contact (OWC) is essential for volumetric calculations and important for detailed petrophysical calculations so there are challenges faces this work:

- Density differences
- Low salinity (fresh) water from resistivity measurements cannot certainty locate fluids contacts.

Those challenges can be solved by using excess pressure which its improved interpretation of wireline pressure data.

3.2 Data description:

3.2.1 Logging data:

Logging data through well **N-12** used in this project comprises of Spontaneous Potential (SP) log, Laterolog Shallow (LLS), Laterolog Deep (LLD), Gamma Ray (GR) log, Micro Spherical Focus Log (MSFL), Neutron log, Formation Density Log (FDL).

Qualitative analysis of well log includesdetermination of porous zones, sand and shale base line, water bearing formation, hydrocarbon depletion zone, and oil water contact(OWC).

Quantitative analysis obtains: porosity, water and hydrocarbon saturation, shale volume, mud filtrate resistivity, and calculation of formation temperature (RPCES 2006).

Porosity value obtained from density log and corrected from shale volume (Vsh) and hydrocarbon fluid contain. Hydrocarbon saturation is estimated from water saturations which are calculated from true resistivity (Rt), shale volume (Vsh) and corrected from porosity parameters.

3.2.2 Pressure data:

The raw data in the table below:

Table 2: Pressure data sheet

Test No.	Depth (m)	I.H.S. pressure(psi)	F.H.S. pressure(psi)	Pretest(psi)	Temperature(°C)	Code
1	1126	2042.79	2041.34	1427.24	62.81	V
2	1127	2043	2042.64	#	62.78	**T**
3	1126.8	2042.14	2041.06	1423.52	63.04	V
4	1128	2043.18	2043.17	#	#	**T**
5	1127.8	2042.54	2042.47	#	#	**T**
6	1129	2044.27	2043.71	1417.03	63.13	V
7	1130	2045.22	2044.54	1418.08	63.15	V
8	1132	2047.8	2046.23	1421.63	63.24	V
9	1134	2049.53	2049.27	#	63	**T**
10	1136	2052.41	2051.89	1425.89	63.22	V
11	1138	2055.16	2054.36	1428.71	63.26	V
12	1140	2057.56	2057.04	1431.54	63.25	V
13	1174.5	2119.14	2117.96	1488.51	63.3	V
14	1175.5	2119.42	2118.86	#	63.46	**LS**
15	1176.5	2120.34	2118.97	1488.18	63.63	V
16	1177.5	2120.43	2119.05	1488.73	63.76	V
17	1178.5	2120.37	2119.27	1489.99	63.86	V
18	1180	2121.63	2120.31	1490.61	63.94	V
19	1181.5	2122.69	2121.88	1492.06	63.96	V
20	1183	2124.19	2123.6	1492.73	63.99	V
21	1184.5	2125.9	2125.3	1494.42	64	V
22	1186	2127.57	2126.92	1496.45	64	V
23	1864	3372.32	3370.39	2305.09	72.82	V
24	1865	3372.12	3371.25	2306.01	73.15	V
25	1866	3372.96	3372.16	2307.09	73.45	V
26	1867	3373.79	3373.2	2308.35	73.62	V
27	1869.5	3377.64	3375.8	2310.56	74.06	V
28	1870.5	3429.98	3429.53	2310.56	71.89	V
29	1871.5	3430.91	3430.63	2311.6	72.32	V
30	1872.5	3432.26	3432.2	2312.71	72.63	V
31	1874.5	3435.65	3435.54	2315.48	72.82	V
32	1876	3437.83	3437.67	2317.54	73.04	V
33	1877.5	3440.17	3439.7	2319.61	73.3	V
34	1879	3442.2	3441.53	2321.59	73.55	V
35	1881	3444.8	3444.72	2324.75	73.71	V
36	1883	3448.16	3447.94	2327.1	73.73	V

Table 3: Codes of pressure data sheet

D	Dry
T	Tight
LS	Lost seal
SC	Supercharged
V	Valid

Data were selected from **N-12Pressure Tests** to evaluate pressure gradient. There are six tested intervals:

- Zone1 (3704.068-3713,9)ft
- Zone2 (3727.034-3740.15) ft
- Zone3 (3859.908-3866.49) ft
- Zone4 (3871.391-3891.076)ft
- Zone5 (6115-6133.530) ft
- Zone6 (6136.811-6177.617)ft

3.3 Data quality check:

Analysis of WFT data, there is 36 pretest pressure points in the well N-12, 31 pretest points are good and are adopted to perform pressure and fluid type analysis.

The other 5 pretest points were rejected due to the failure of: Lost seal, supercharged, dry test, and tight test.

3.4 Pressure gradient estimation:

According to the difference in fluid densities, a difference in the pressure gradient occurs during the measurement.

Obtained by inversely slope from plot formation pressure versus depth.

The ranges which have been used are:

- Gas gradient range from (0.08-0.18) psi/ft.
- Oil gradient range from (0.28-0.39) psi/ft.
- Water gradient from (0.433-0.465) psi/ft.
    - Fresh water gradient = 0.433 psi/ft.
    - Saline water gradient = 0.465 psi/ft

Pressure gradient depends on slope for its calculation, and the slope calculated from the following linear equation:

y = ax + b2.1

Where:

y = Depth

a = slope

x = pressure

so:

Gradient = $\frac{\mathbf{1}}{\boldsymbol{slope}}$ **3.2**

3.5 Interpretation of WFT:

1-Formation pressure.2-Drawdown mobility.

3-Downhole fluid analysis: fluid color and compositional analysis, asphaltenes content, viscosity, density, florescence, resistivity, and pH. 4-Hydrocarbon composition (C 1, C 2 , C 3–C 5, and C 6+).

5-Gas/oil ratio (GOR).6-Sample contamination monitoring**.**

3.6 Standard Interpretation:

A) Grading of pressure and mobility quality.

B) Pressure gradient analysis.

C) Excess pressure analysis.

3.7 Interpretation Using Excess Pressure:

Fluid density, fluid contacts, and pressure barriers can be interpreted from excess-pressure plots. Fluid density is estimated by rotating the excess-pressure trend to vertical. Selection of fluid density is an iterative process; thereby, barriers and slope changes canbe detected during the density-estimation process. If a possible barrier or contact is identified, the depth range of analyzed samples is narrowed so that only a single fluid is evaluated. In contrast, fluid density is calculated from pressure-depth plots by regression. Pressure-barrier or small density changes may not be noticed before regression; thus, the density calculated from the trend may not represent the actual fluid density.

Slope change indicates fluid-density change. Fluid density changes at fluid contacts and across petroleum sealsfigure 3-1. On excess-pressure plots, clockwise tilt from vertical indicates a density that is lower than modeled. Expanding the scale increases the excess-pressure slope of fluids having a density different from modeled density, but vertical excess-pressure trends do not change as the scale expands. Scale can be expanded as much as needed to detect small density changes.

Pressure-depth plots of most data lack sufficient resolution to differentiate between free-water level (elevation where capillary pressure is zero) and petroleum-water contact (elevation with lowest moveable petroleum), but these surfaces can be distinguished using excess pressure plots. Intersection of the petroleum and water trends is the free-water level, because at this elevation, the petroleum and water pressures are the same. Petroleum-water contact occurs at or below the lowest test that lies on the petroleum-density trend. The difference in petroleum-water contact elevation and free water level indicates wetting conditions in the reservoir (Desbrandes and Gualdron, 1987).

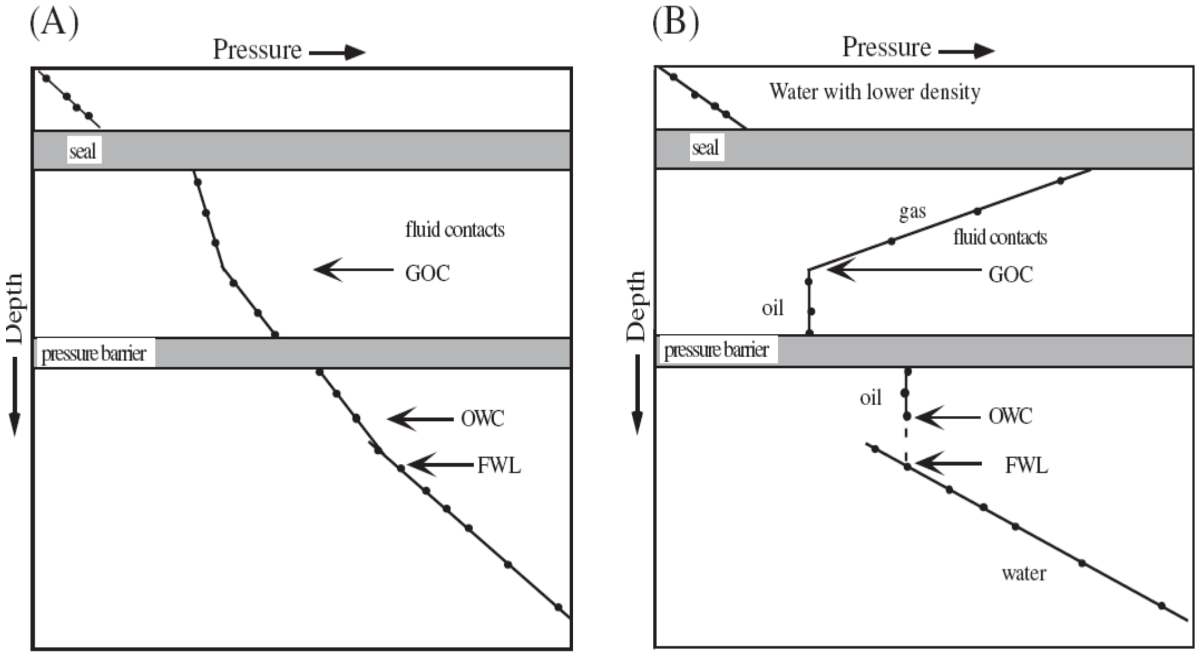

Figure : Identification of fluid contacts and pressure barriers using pressure plots (Desbrandes and Gualdron, 1987)

Abrupt offsets of pressure-depth trends indicate pressure seals. Pressure seals plot as offsets betweentilted trends on pressure-depth diagrams (Figure 3.1A). These offsets may not be recognized where the magnitude of the offset is small compared to the total pressure change across the barrier. Excess-pressure plots remove most of the total pressure change across the barrier, and thus, excess-pressure scale can be expanded to visualize the small excess-pressure difference (Figure 3.1B). If fluid density changes across a pressure barrier (such as the top seal), the excess-pressure slope as well as the magnitude of the excess pressure differs.

Reservoir-saturation history:

Reservoir saturation history can be evaluated by comparing petroleum-water contact estimated from porosity-resistivity logging to the contact estimated from wireline pressure data.If porosity-resistivity logging indicates a deeper petroleum contact than estimated from wireline pressure data, the petroleum-water contact has probably moved upward since trapping. The deeper petroleum is residual, and the permeability-saturation relationship may fall on the imbibition curve higher in the reservoir.

The quantitative form of this relationship is the following (Hubbert, 1956):

$$\textbf{Excess pressure} = \rho g z + Pm \qquad \textbf{3.3}$$

$$\textbf{Excess pressure} = 0.4335 \rho z + Pm \qquad \textbf{3.4}$$

(Ft, g/cm3, and psi)

where Pm is the measured pressure at depth z relative to the datum (negative downward), ρ is the density of the fluid at reservoir conditions, and g is the pressure gradient for fluid having a density of 1 g/cm3. Excess pressure can be calculated using any datum. The magnitude of the excess pressure has less meaning than excess-pressure differences calculated using the same datum and fluid density.

4 Chapter Four:Results & Discussions

4.1 Logging Data:

4.1.1 Description of tested zones:

We have lass file of well N-12, entered in interactive petro-physics (IP) software and by readings of gamma ray log (GR), and (SP) deflection we defined sand formations

and corrected them from gamma ray histogram.

To select zones we do the following:

Firstly we selected depths which their tested codes indicate V(Valid tests) from pressure data sheet, after that defined those depths on well N-12 which we entered in IP(Interactive petro-physics) software.

Secondly we have 31 valid test points, extracted from them six interested zones by interpretation of clay volume (Vsh) on (IP).

The description of these tested zones on the table below:

Table 4: Description of tested zones

Zones	**Depth, ft**	**Lithology**	**Average porosity(φ)%**	**Average resistivity(ohm.m)**	**Fluid content**	**Temperature(°F)**
Zone1	3704.068-3713.900	Shaley-sand	0.333	10.61	moveable hydrocarbon	145.706
Zone2	3727.034-3740.150	Shaley-sand	0.327	6.655	moveable hydrocarbon	145.832
Zone3	3859.908-3866.400	Shaley-sand	0.306	11.60	moveable hydrocarbon	146.835
Zone4	3871.390-13891.076	Shaley-sand	0.29	7.58	moveable hydrocarbon	147.177
Zone5	6115.485-6133.530	Sand	0.223	211.40	Oil	163.868
Zone6	6136.811-6177.617	Sand	0.219	407.29	Water	163.589

4.2 Pressure Gradient:

Analysis of fluid type, totally 31pretest point have been analyzed used to perform advanced pressure analysis and to determine formation fluid type these reliable pretest point can be divided into 6 zones:

Zone1 (3704.068ft-3713,9ft):

There are 3 points in this zone. theirR-square is 0.9984. So they can be zoned

Zone2 (3727.034ft-3740.15ft):

There are 3 points in this zone. their r-square is 0.9984. So they can be zoned

Zone3 (3859.908ft-3866.49ft):There are 3 points in this zone. their R-square is 0.9997. So they can be zoned

Zone4 (3871.391ft-3891.076ft):

There are 5 points in this zone. their R-square is 0.9577. So they can be zoned

Zone5 (6115ft-6133.530ft):

There are 5 points in this zone. their R-square is 0.9647. So they can be zoned

Zone6 (6136.811ft-6177.617ft):

There are 9 points in this zone. their R-square is 0.9974. So they can be zoned

In this section, the pressure gradient has been analysed by considering various cases in order to obtain the best results. Four cases were considered as follows:

Case 1:

zone (1) & (2) together:

Depth (3704.068-3740.157)ft

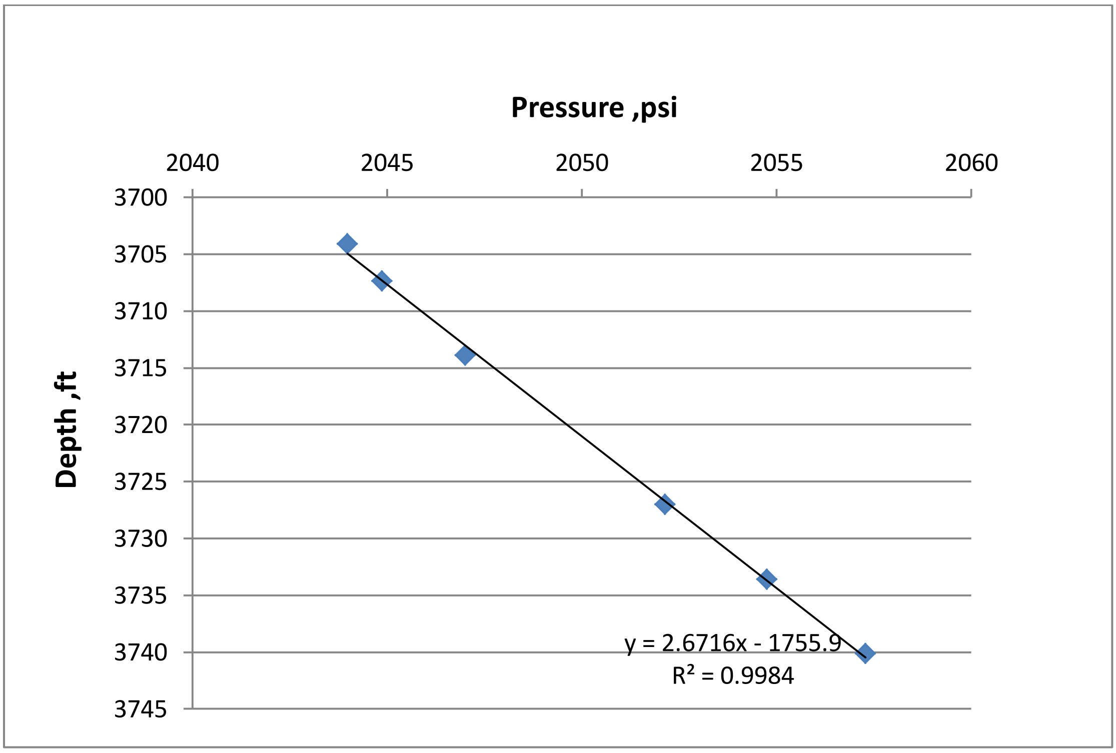

Figure 4-1: pressure gradient for zone 1&2

y = 2.6716x – 1755.9

Gradient = $\frac{1}{2.6716}$ = 0.374 psi

Possibly oil

Case 2:

zone (3) only:

Depth (3859.908- 3866.47)ft

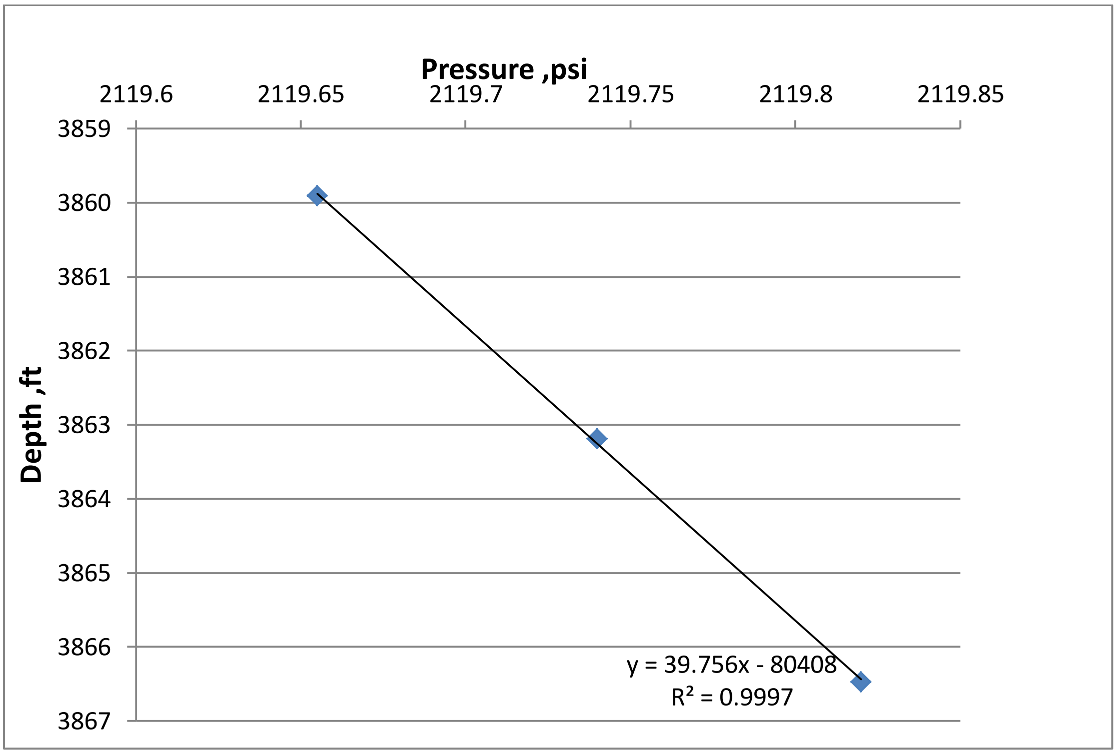

Figure 4-2: Pressure gradient for zone 3 only

y = 39.756x – 80408

Gradient = 0.025 psi

Possibly gas

Case 3:

Zone(3)&(4):

Depth(2119.655-2127.245)ft

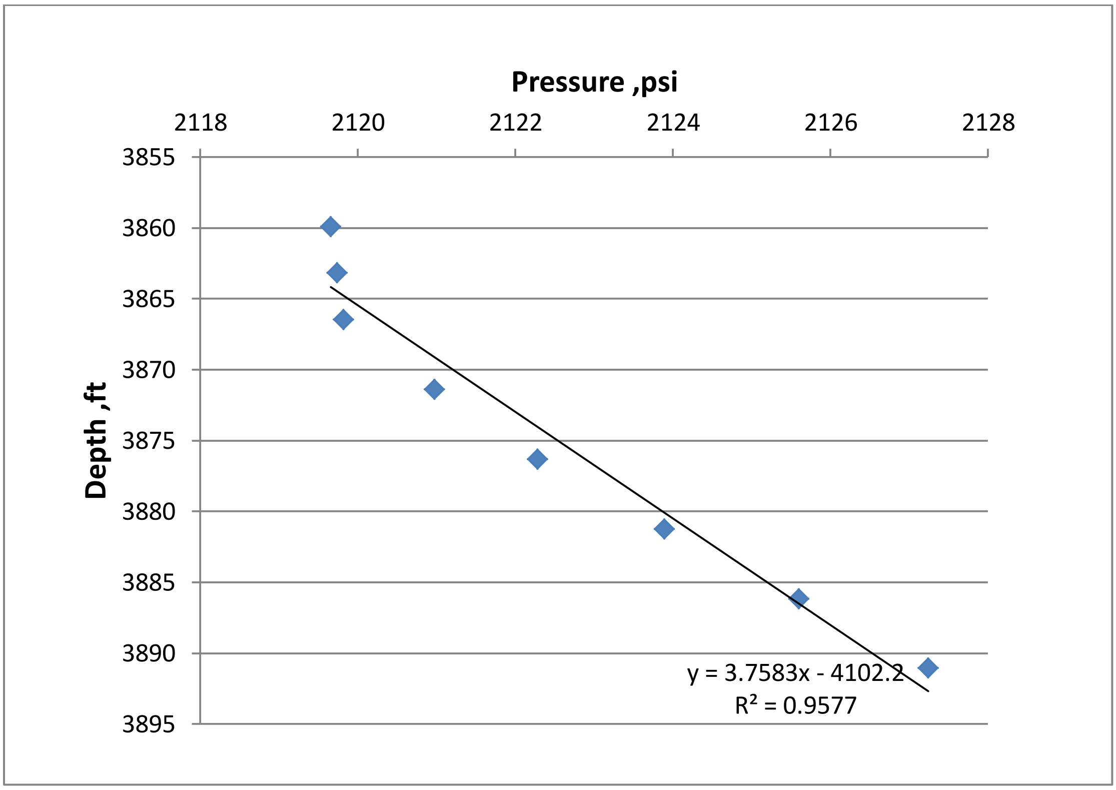

Figure 4-3: Pressure gradient for zone 3&4

y = 3.7583x – 4102.2

Gradient = 0.266 psi

Possibly oil

Case 4:

Zone 5&6:

Depth (6115.486- 6177.822) ft

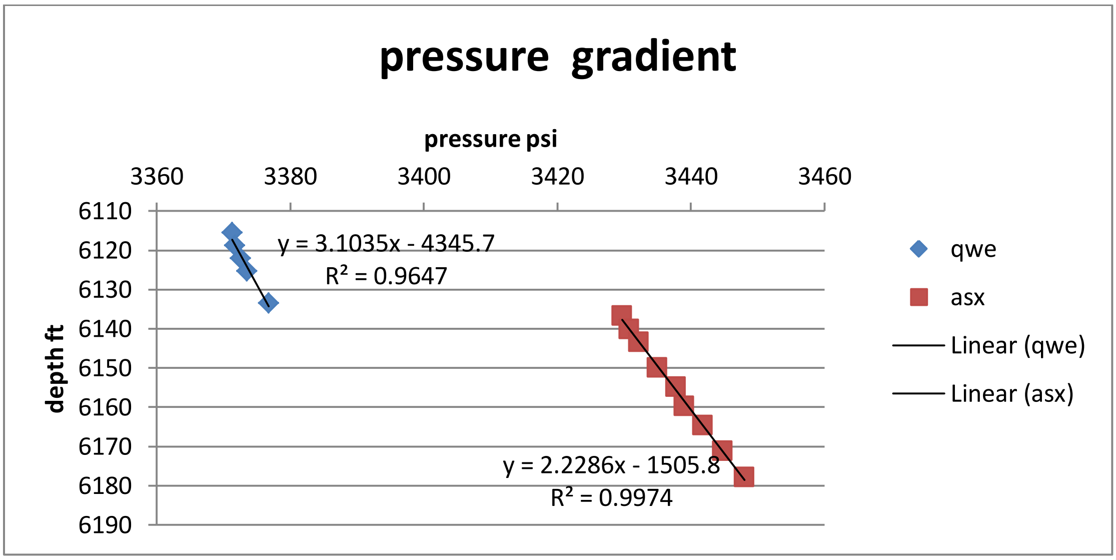

Figure 4-4: Pressure gradient for zone 5&6

First for zone 5:

y = 3.1035x – 4345.7

Gradient = 0.322psi

Zone 5 Possibly oil

For zone 6:

y = 2.2286x – 1505.8

Gradient = 0.448psi

Zone 6 Possibly water

4.3 Pressure data:

Here is the pressure data of only valid tests after performing excess pressure equation, and converting depth's units from meters to feets.

Table 5: Excess pressure data sheet

depth, m	pressure, psi	depth, ft	Z, ft	pretest, psi	Excess p, psi
1129	2043.99	3704.068	2473.754	1417.03	2216.38889
1130	2044.88	3707.349	2470.473	1418.08	2216.37874
1132	2047.015	3713.911	2463.911	1421.63	2217.80842
1136	2052.15	3727.034	2450.788	1425.89	2217.82779
1138	2054.76	3733.596	2444.226	1428.71	2218.52748
1140	2057.3	3740.157	2437.665	1431.54	2219.23716
1176.5	2119.655	3859.908	2317.914	1488.18	1866.75096
1177.5	2119.74	3863.189	2314.633	1488.73	1866.76512
1178.5	2119.82	3866.47	2311.352	1489.99	1867.48928
1180	2120.97	3871.391	2306.431	1490.61	1867.30552
1181.5	2122.285	3876.312	2301.51	1492.06	1867.95176
1183	2123.895	3881.234	2296.588	1492.73	1867.818
1184.5	2125.6	3886.155	2291.667	1494.42	1868.70424
1186	2127.245	3891.076	2286.746	1496.45	1869.93048
1864	3371.35	6115.486	62.33644	2305.09	2320.02382
1865	3371.68	6118.766	59.0556	2306.01	2320.15783
1866	3372.56	6122.047	55.77476	2307.09	2320.45185
1867	3373.5	6125.328	52.49392	2308.35	2320.92586
1869.5	3376.8	6133.53	44.29182	2310.56	2321.1709
1870.5	3429.76	6136.811	41.01098	2310.56	2329.65524
1871.5	3430.77	6140.092	37.73014	2311.6	2329.16764
1872.5	3432.23	6143.373	34.4493	2312.71	2328.75004
1874.5	3435	6149.934	27.88762	2315.48	2328.46484
1876	3437.75	6154.856	22.96636	2317.54	2328.23343
1877.5	3439	6159.777	18.0451	2319.61	2328.01203
1879	3441.86	6164.698	13.12384	2321.59	2327.70063
1881	3444.76	6171.26	6.562157	2324.75	2327.80543
1883	3448.05	6177.822	0.000478	2327.1	2327.10022

4.4 Excess Pressure:

When we plot excess pressure versus depths we have four scenarios:

Scenario1:

All zones

Depth (3704.068-6177.822)ft

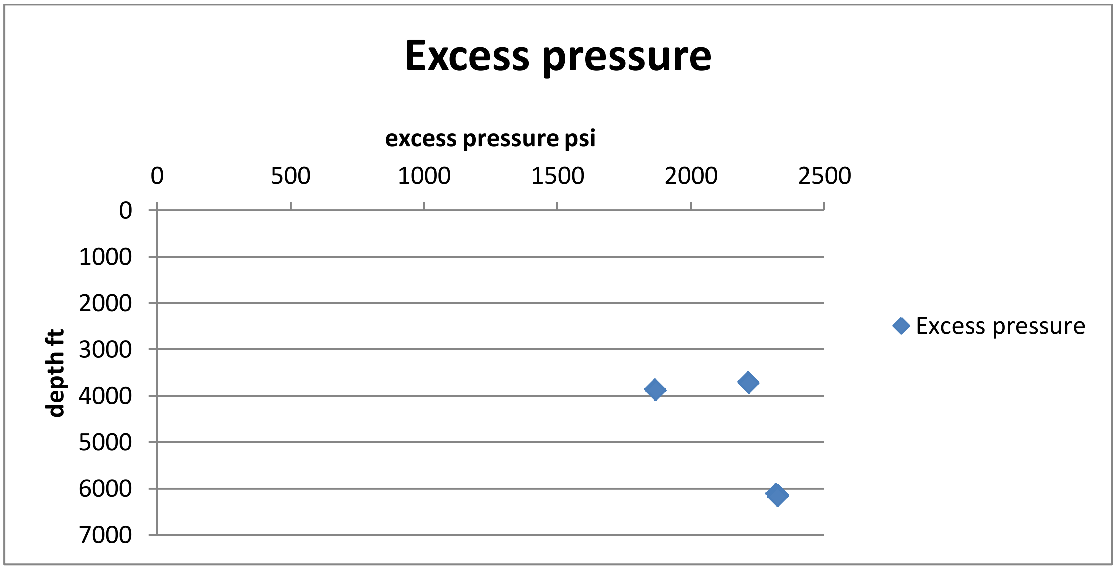

Figure 4-5: Excess pressure for all zones

Scenario2:

Zone1&2

Depth(3704.068-3740.157)ft

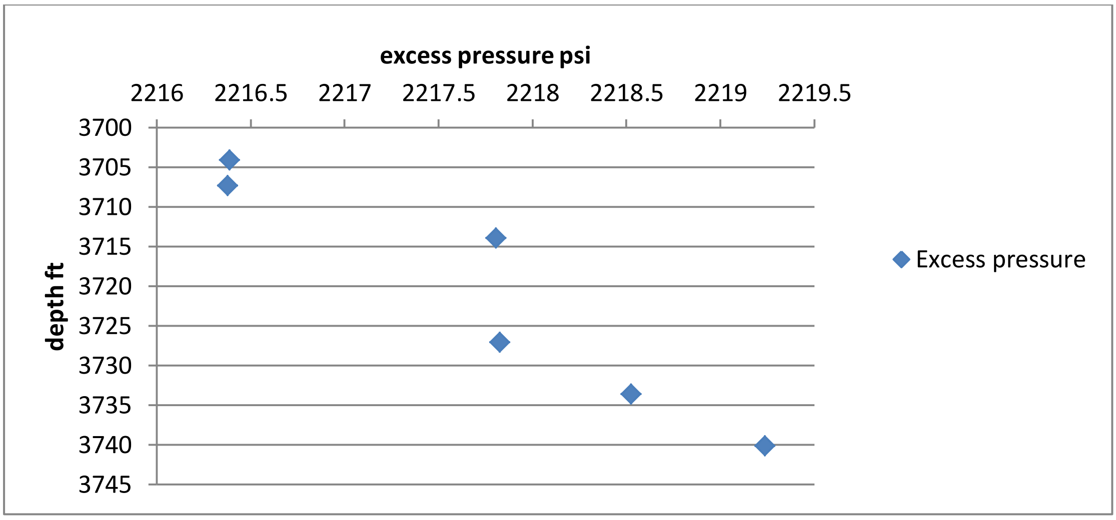

Figure 4-6: Excess pressure for zone 1&2

Scenario3:

Zone3&4

Depth(3859.908-3891.076)ft

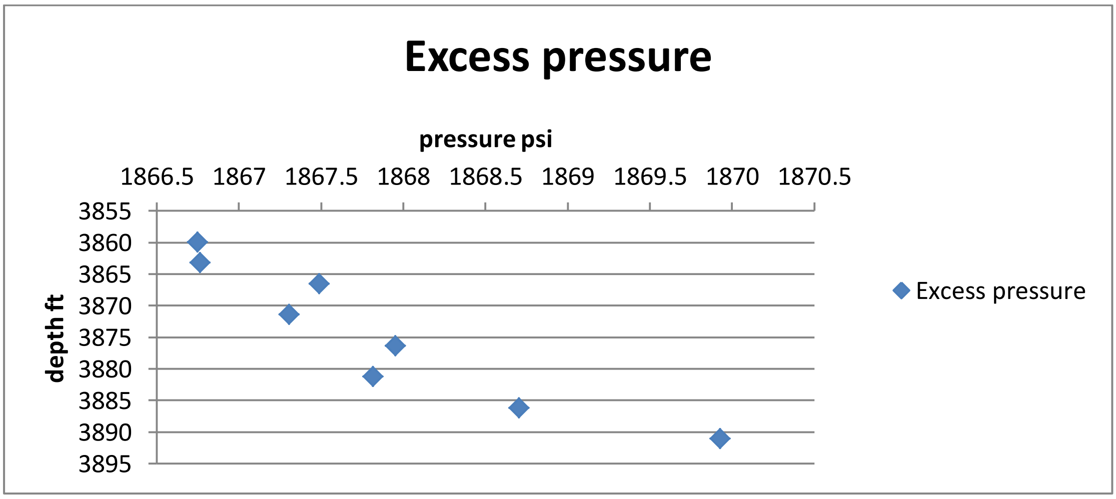

Figure 4-7: Excess pressure foe zone 3&4

Scenario4:

Zone5&6 together

Depth(6115.485-6177.821)ft

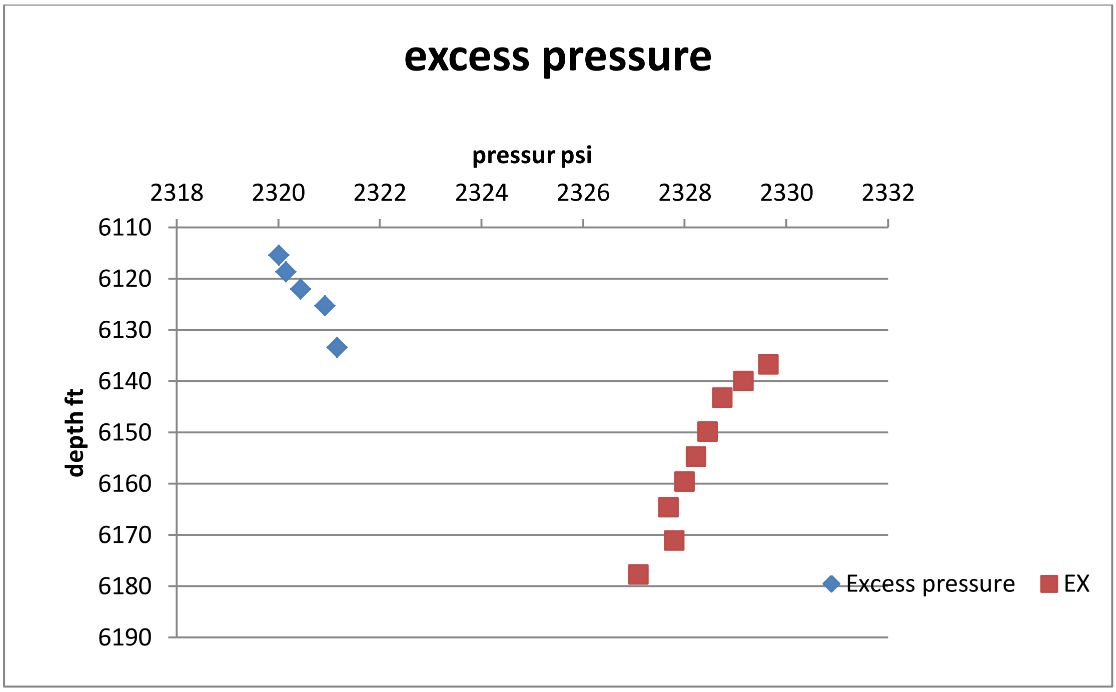

Figure 4-8: Excess pressure for zone 5&6

From pressure gradient zone 6 is water, so we can plot formation pressure versus depth we can get the free water level(FWL).

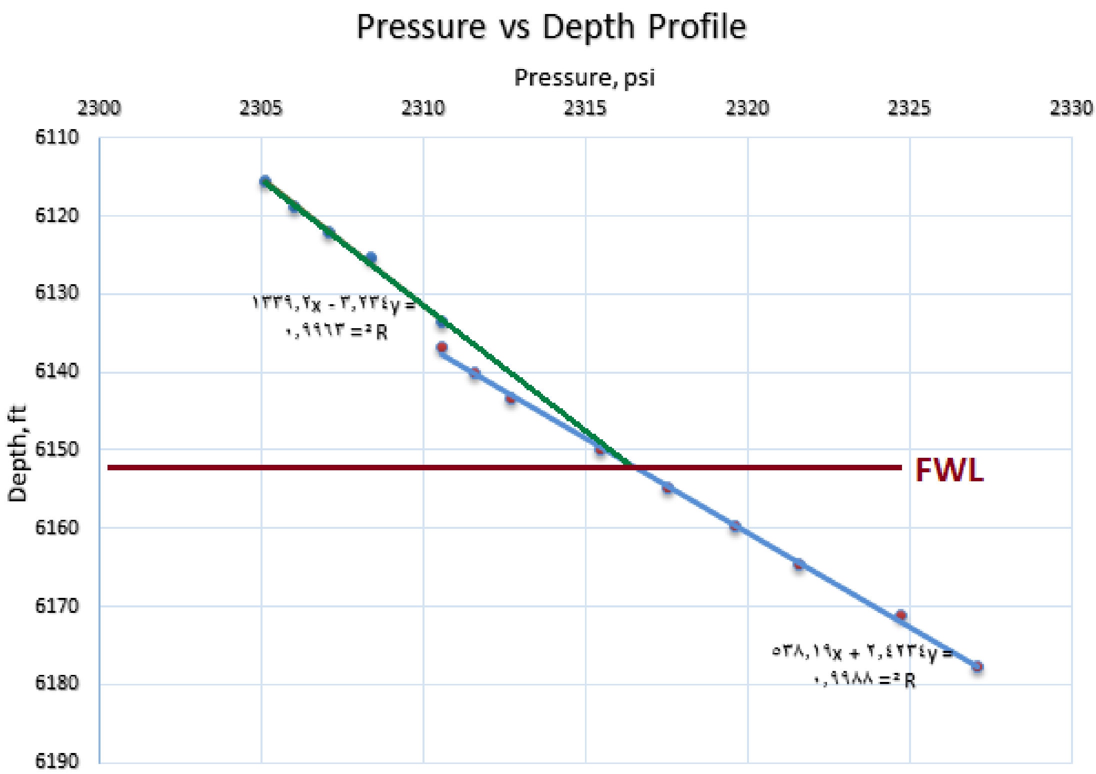

Figure 4-9: Pressure Profile(formation pressure vs depth)

From the above figure the intersect between the oil pressure gradient and the water pressure gradient result **Free Water Level (FWL)**in the depth 1875m(6151.575) ft.

5 Chapter Five: conclusions and recommendations

5.1 Conclusions:

From this study conclusion can be summarized as follows:1-The excess pressure of static, homogeneous fluid in good pressure communication will not change with depth.

2-Excess pressure variation with depth indicates barriers and fluid contacts.3-Using good data, within-well systematic excess pressure differences of less than 5 kPa (0.7 psi) can be interpreted in terms of pressure barriers and fluid density changes.

4-Small anomalies in the buildup-pressure curve indicate pressure errors on the psi scale caused by leaking probe seals,probe plugging, and gauge problems.

5-Most bad tests have to be discarded, but a few can be corrected if problems are minor.

6-Small excess-pressure differences between wells cannot be detected as easily as within-well excess-pressure differences, because absolute-depth and pressure calibration between wells is poorer than within-well pressure Resolution.

7- Fluid-density resolution is sufficiently high to use for new applications. These include petroleum quality evaluation, barrier detection by small density differences.

5.2 Recommendations:

- The study can be more accurate and effective if the other tools were used (e.g. DST tool) and more geological data were used.
- To get more accurate results and more samples: more wireline formation testing are needed.
- The end user at least qualitatively examine buildupcurves for all tests prior to data analysis.

Appendix

Appendix 1:

Select zones of interest from pressure data sheet in (IP) softwareby interpretation of clay volume:

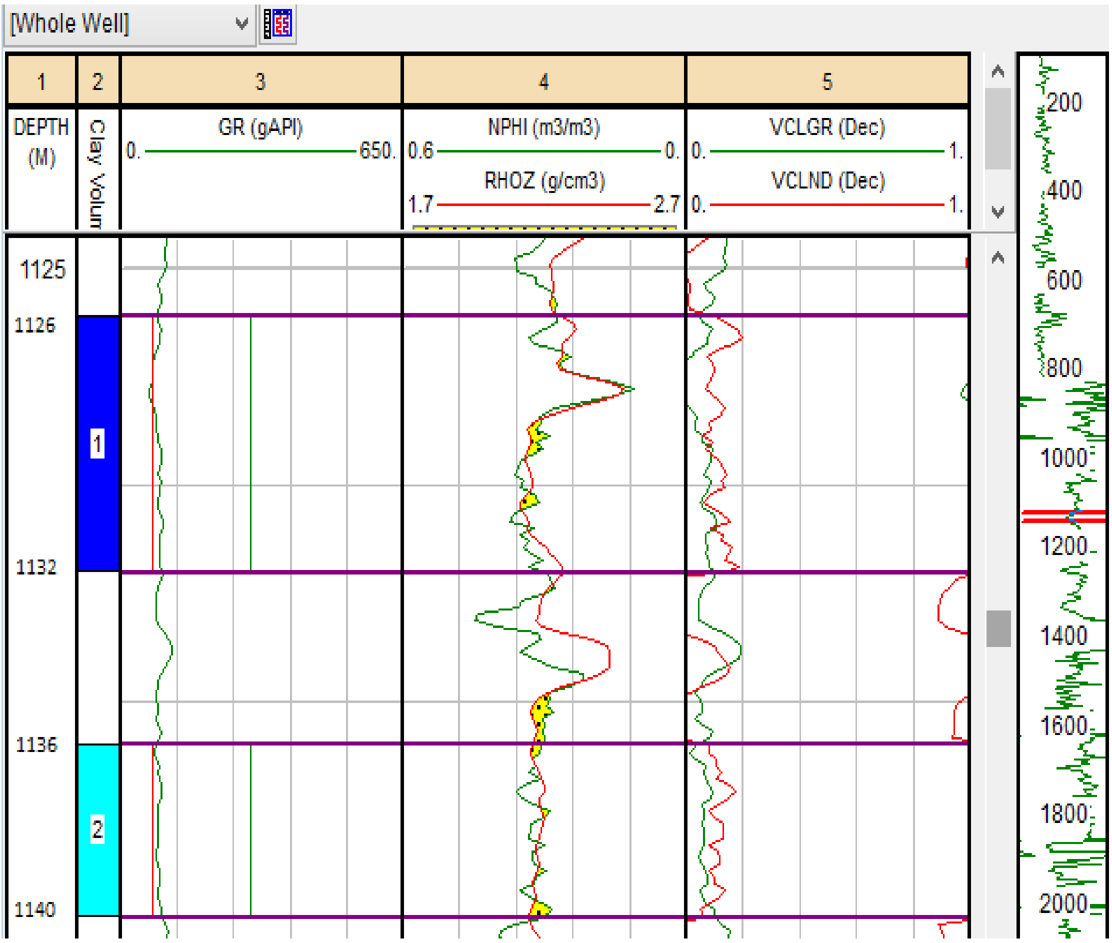

Figure 5-1: zones of interest(A)

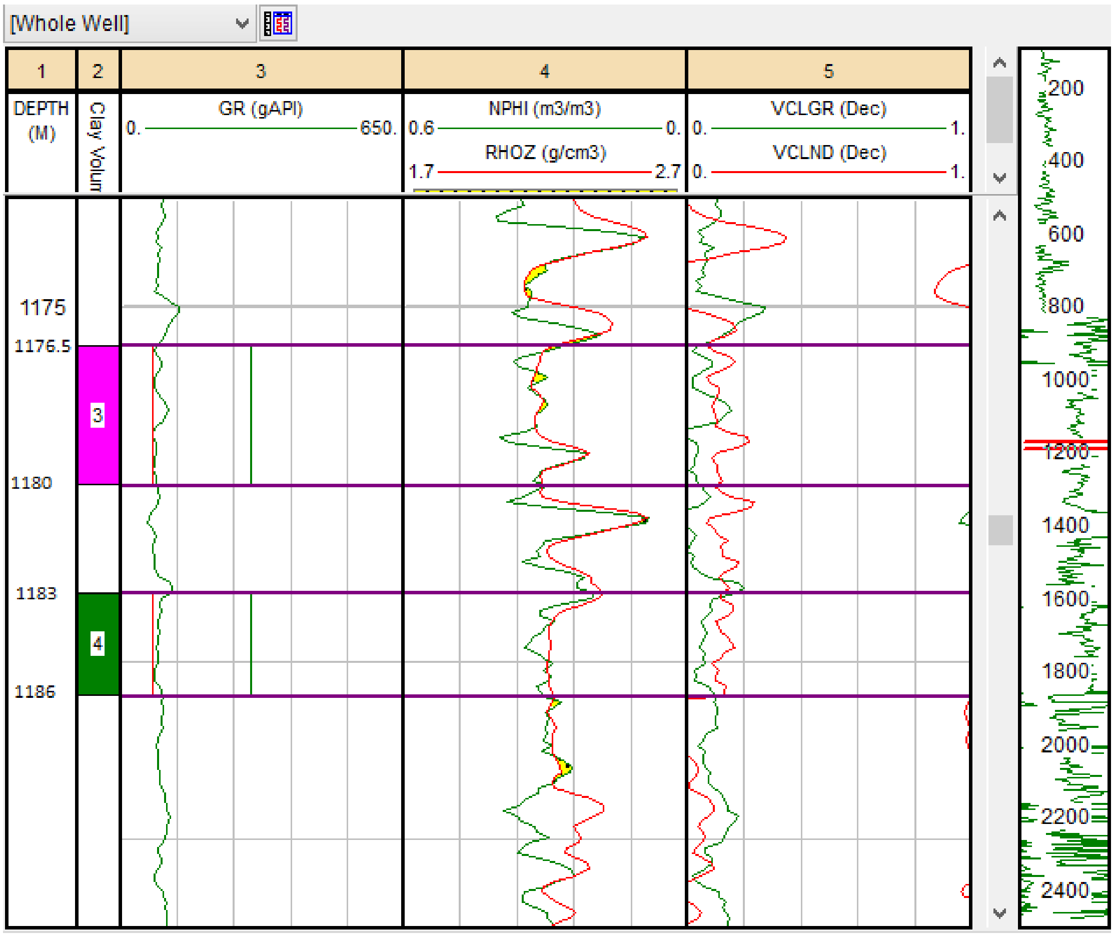

Figure 5-2: Zones of interest(B)

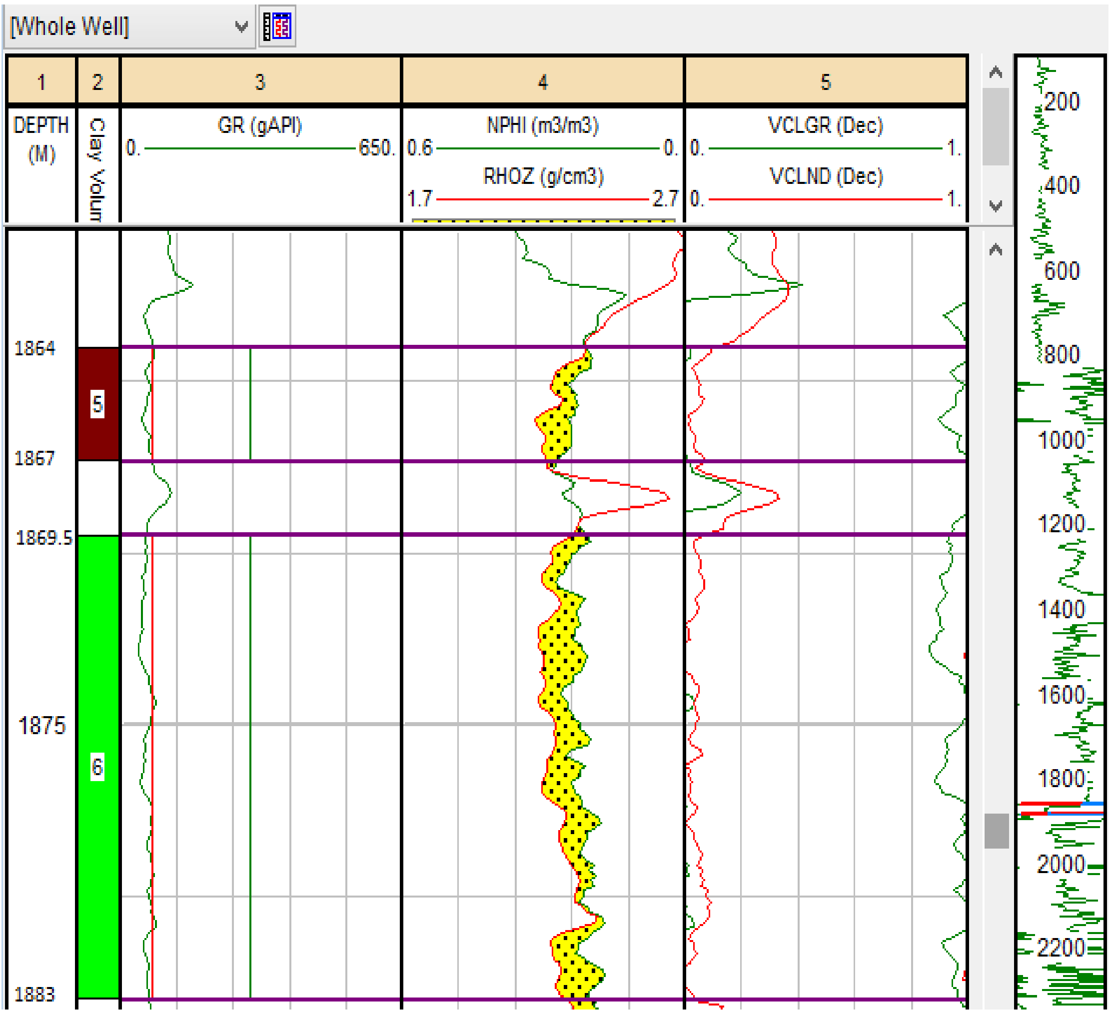

Figure 5-3: Zones of interest(C)

Appendix 2:

Porosity and saturation calculation from interpretation

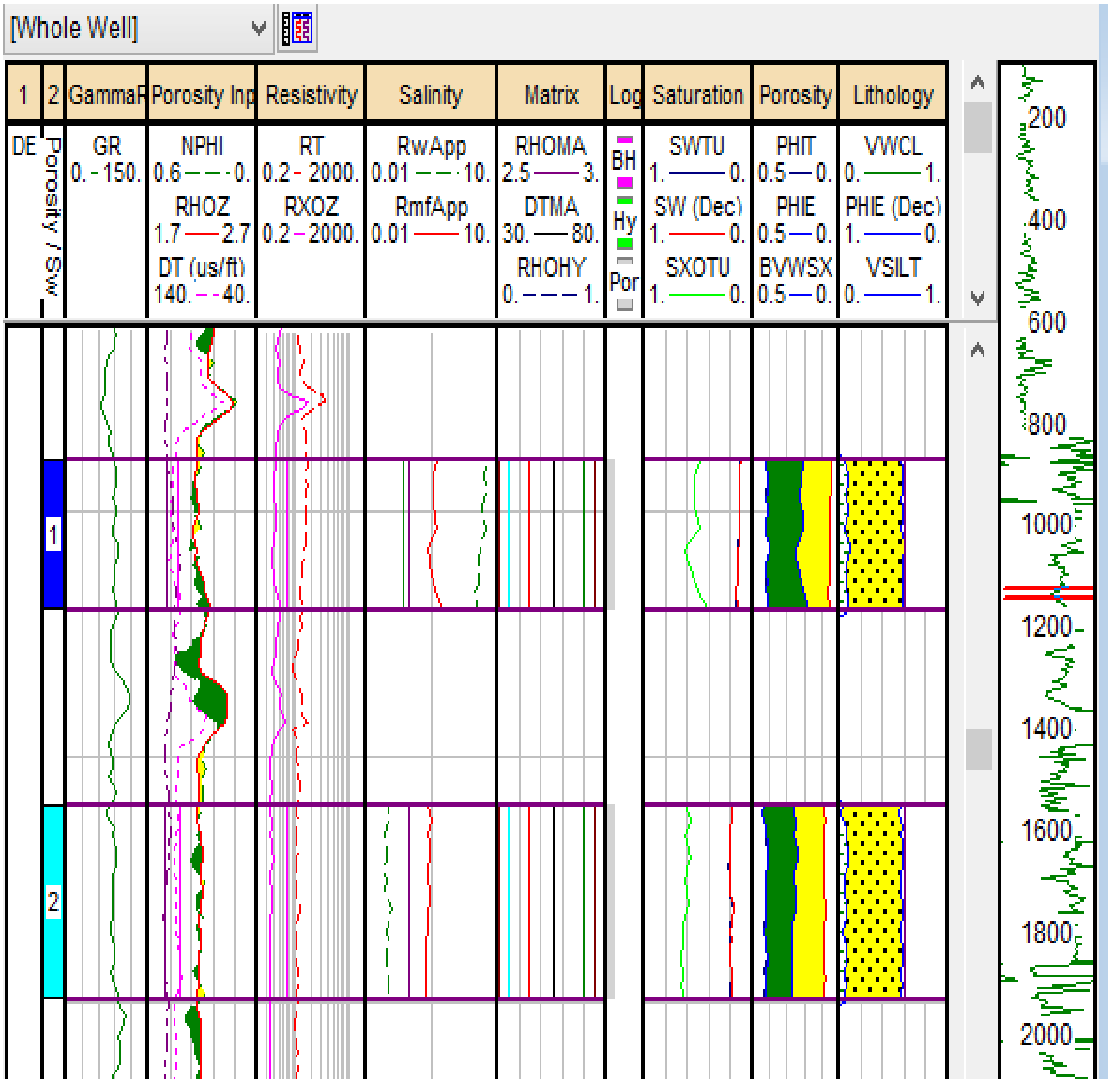

Figure 5-4: Zones 1&2 description

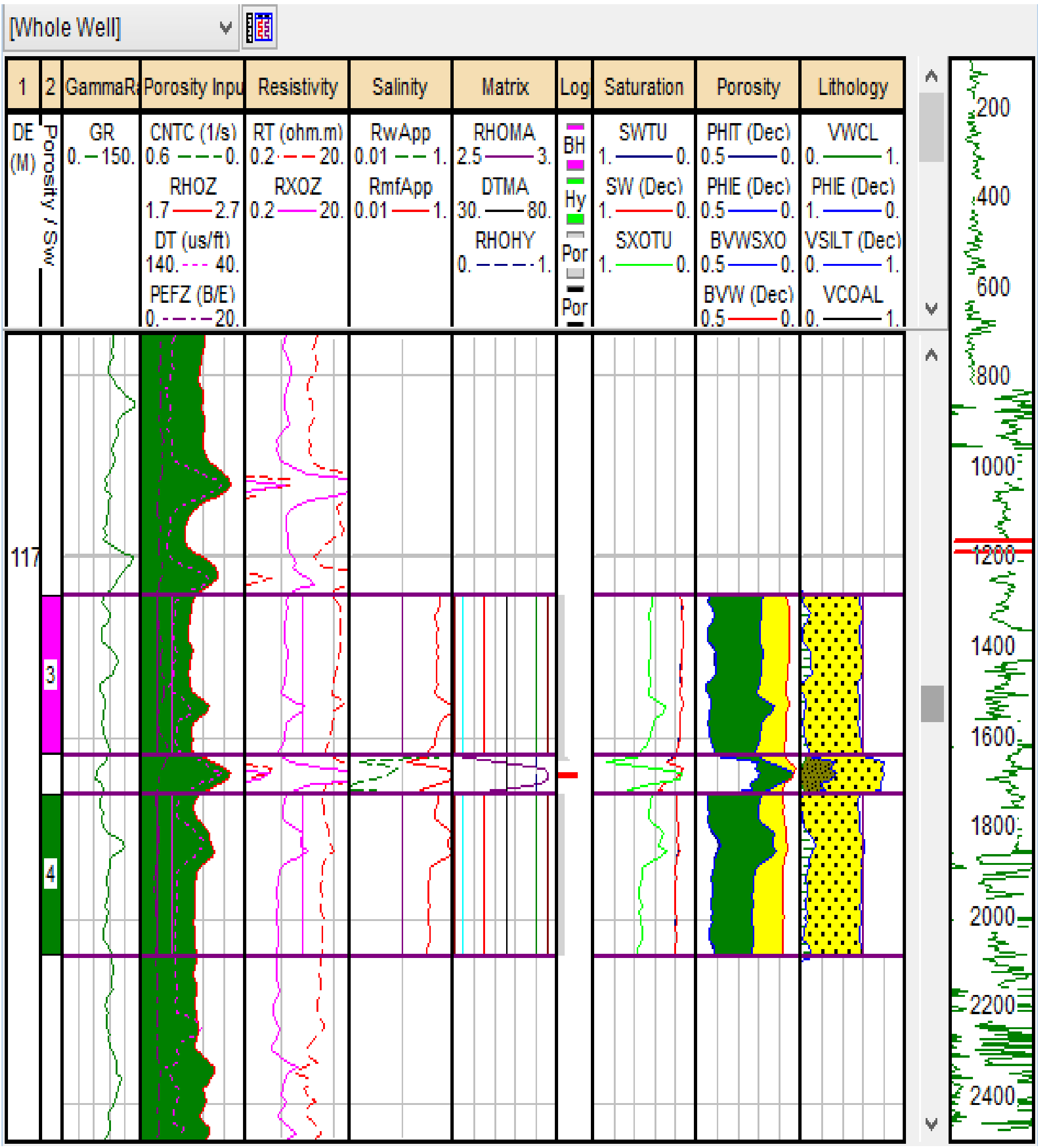

Figure 5-5: Zones 3&4 description

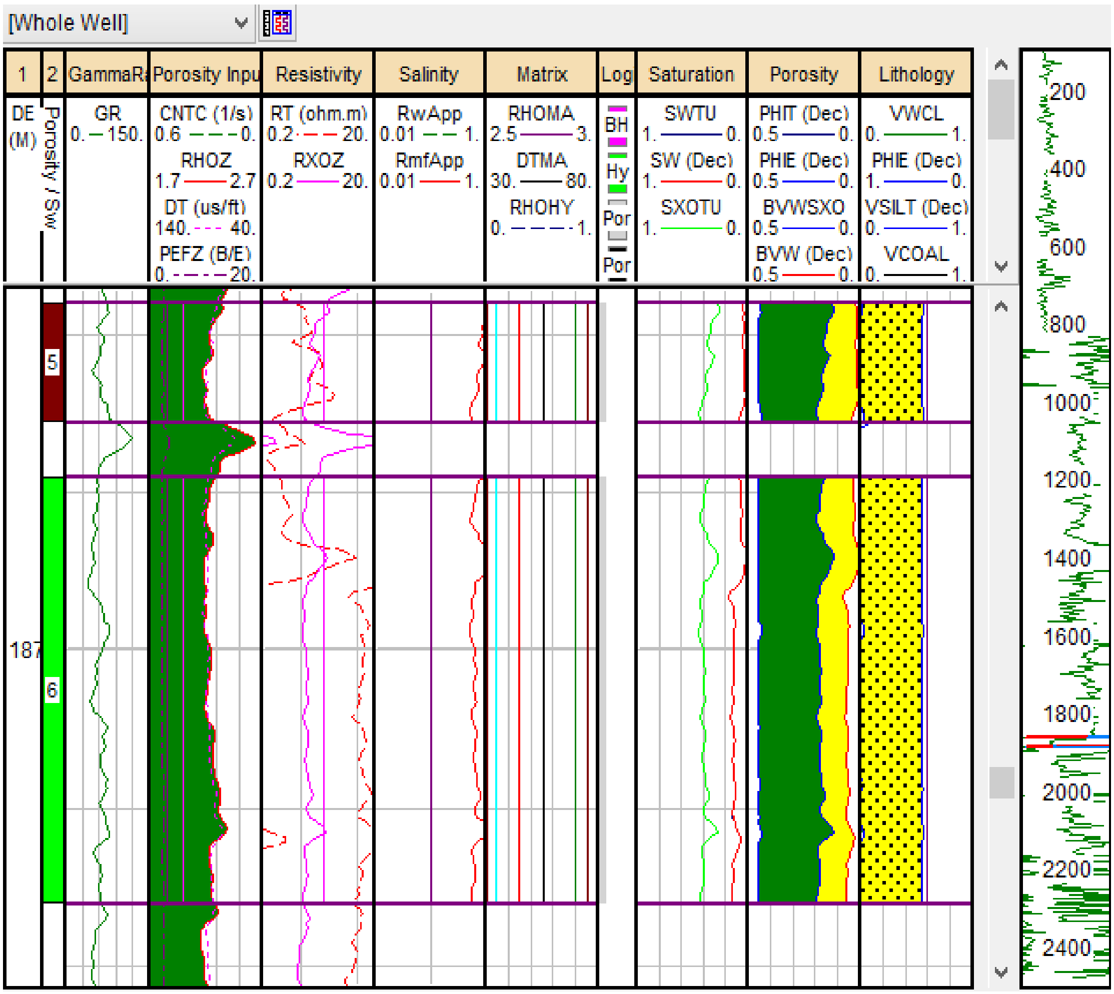

Figure 5-6: Zones 5&6 description

Appendix 3:

Integration WFT with wireline logging:

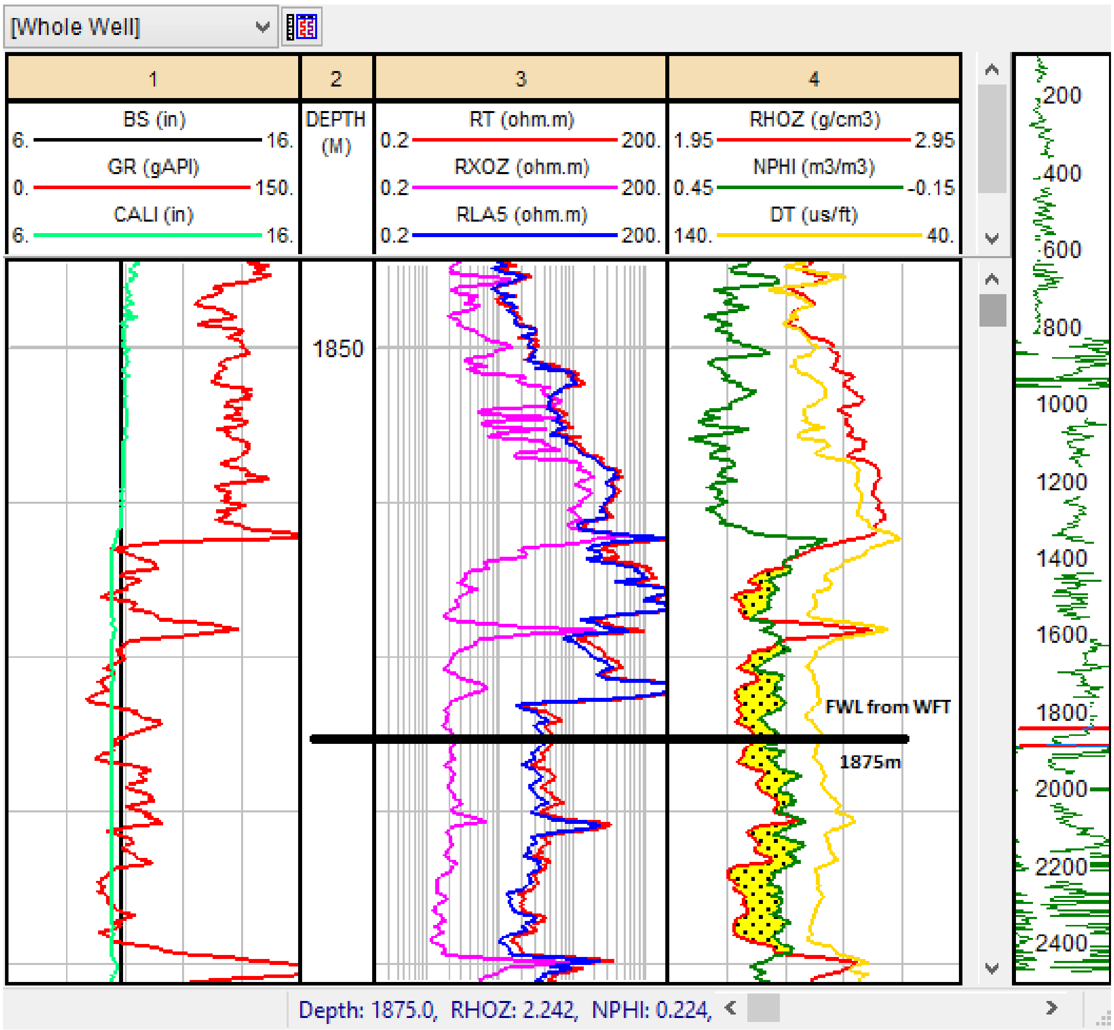

Figure 5-7: Interpretation of logging

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