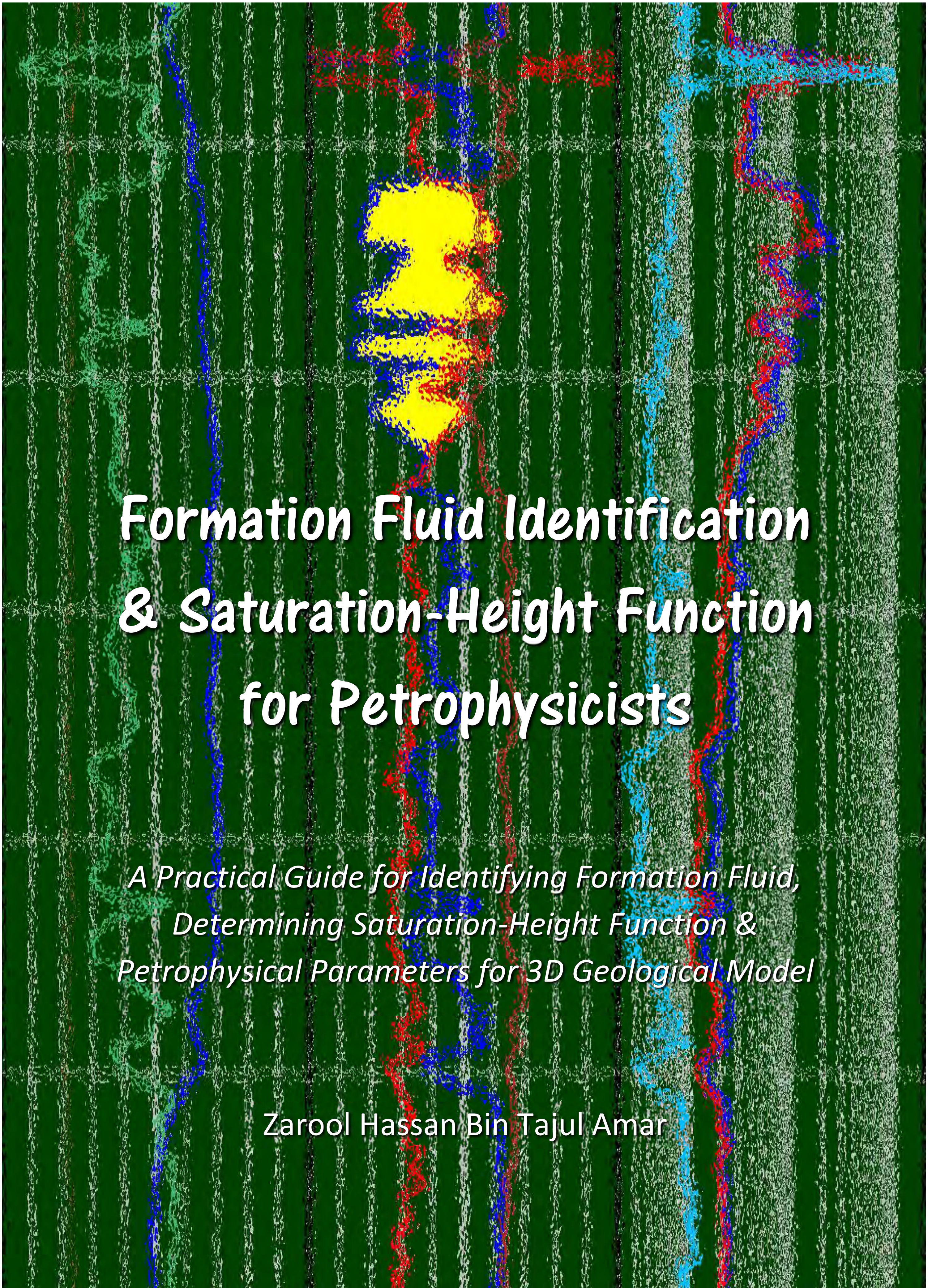

Formation Fluid Identification & Saturation-Height Function for Petrophysicists

A Practical Guide for Identifying Formation Fluid, Determining Saturation-Height Function & Petrophysical Parameters for 3D Geological Model

Zarool Hassan Bin Tajul Amar

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RMJ Nexus Global Sdn. Bhd.

This book is dedicated to Mama and Babah for their sacrifices, guidance and love.

To Wan Bong for being part of our lives.

"In an era where petrophysical interpretation is increasingly driven by sophisticated software and automated workflows, this book serves as a timely and important reminder of the enduring value of first principles. "Formation Fluid Identification & Saturation-Height Function for Petrophysicists" by Zarool Hassan Bin Tajul Amar presents a clear, practical, and highly accessible approach to one of the most critical aspects of reservoir evaluation: fluid typing and saturation-height function modelling, particularly in data-limited environments.

What sets this book apart is its unwavering emphasis on fundamentals. Zarool successfully bridges theory and practice by demonstrating how conventional logs, when properly understood and integrated, can yield robust and reliable interpretations. The methodologies are logically structured and supported by numerous field examples that reflect real challenges faced by today's petrophysicists.

The detailed explanations, combined with step-by-step workflows, make complex concepts easy to follow and implement. More importantly, the book captures valuable practical insights and subtle interpretation nuances that are often overlooked in modern, software-centric environments. These are hard-earned lessons that can only come from extensive hands-on experience.

This book will be particularly beneficial for young petrophysicists building a strong technical foundation, while also serving as an excellent reference for experienced practitioners seeking to revisit and reinforce core principles. In my view, this is an essential read for anyone involved in petrophysics, reservoir characterization, and 3D reservoir modelling. It not only enhances technical understanding but also reinforces the disciplined, critical thinking required to deliver reliable subsurface evaluations."

Thanapala Singam Murugesu
Petrophysics Custodian
PETRONAS

Preface

This book describes a saturation-height function technique that predicts water saturations above free-water-level needed for 3D geological model (3D geomodel). The technique can easily be formulated and used in different fields with minimal effort.

Developing saturation-height function equations for use in 3D geomodel is now a routine task for petrophysicists. There are, however, numerous theories, techniques and methodologies available in the literature to perform this task that would certainly overwhelm most aspiring and even experienced petrophysicists. After years of trying out various methods and understanding their limitations, the author has identified a simple and robust way to develop saturation-height function that not only works well but is applicable in most reservoirs with minimal modifications.

In addition, methods of determining formation fluid type, fluid contact, porosity, permeability and log-derived water saturation are also presented in this book. In the absence of physical formation fluid samples from either production test or downhole fluid sampling, identification of fluid type is often done using log signatures and formation pressure gradients. These techniques are also presented and explained in detail using field examples.

It is hoped that the techniques and field examples presented here would be helpful and provide clarity in the interpretation of formation fluid types and formulation of saturation-height function that are unfortunately not readily available in the literature.

Notwithstanding, this book would be a good reference for geologists, geophysicists and geomodellers who wish to understand the finer aspects of practices in petrophysics especially in identifying fluid types using logs, formation pressure interpretation and saturation-height function. This would hopefully help them better appreciate all the underlying assumptions and uncertainties in petrophysical interpretation.

In order to benefit more from this book, readers are encouraged to seek other recognised publications for an introduction on the physics of measurements of logging tools and fundamentals of petrophysics.

Acknowledgements

I would like to acknowledge Vestigo Petroleum Sdn. Bhd. for its unwavering support of this publication.

To my lovely wife and wonderful boys, thank you for your enduring love that gives me the strength to write this book.

And finally to all aspiring petrophysicists, may you now have a good night sleep over your formation fluid identifications and saturation-height function calculations!

About the Author

Zarool Hassan Bin Tajul Amar is a petrophysicist with experience in wireline and LWD operations. He is responsible for building saturation-height function, performs reservoir characterization using hydraulic flow unit technique, and identifies fluid contacts for hydrocarbon-in-place calculations in 3D geomodels. He works on fields in the Middle East, South East Asia and Africa in multi-disciplinary teams in pursuit of petrophysical results, and integrates geological and reservoir engineering data for optimum exploitation of oil and gas. He starts his career in the oil and gas industry as a wireline logging engineer performing open-hole and cased hole logging services.

Zarool works on reservoirs that include shaly sands, carbonates, conglomerates and fractures. He integrates various sources of data – viz., mud logs, image logs, NMR, core data (petrography, capillary pressure, routine and SCAL) and formation pressures – to characterize the mechanics of reservoir rock and fluids contained therein.

Besides providing mentoring and guidance to junior petrophysicists, he develops and teaches wireline, LWD logging operations and petrophysical interpretation courses. He authors several technical papers at SPE conferences and has published a paper on reservoir characterisation using hydraulic units.

Zarool holds a Master of Engineering in Petroleum Engineering degree from Heriot-Watt University (Scotland) and a Bachelor of Engineering in Aeronautical Engineering degree from University of Sydney (Australia).

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1. Introduction

The role of petrophysicists and geoscientists in the oil & gas industry have evolved significantly since mid-1990s with the advent of fast computing processing capabilities and advanced 3D geomodel software packages. These tools have allowed geoscientists to integrate many subsurface data on a single platform in order to describe and characterize reservoir rocks, map out formation fluids distribution and ultimately determine hydrocarbon-in-place volumes.

Petrophysicists are traditionally tasked to identify fluid types, determine net pay, and calculate permeability, porosity and water saturation at wellbore location. Nowadays, they are expected to provide information on fluid distribution away from the wellbore for 3D geomodel especially when fluid contacts have not been penetrated by any wells.

This book describes techniques to identify formation fluid and formulation of saturation-height function that petrophysicists provide as inputs towards the construction of a 3D geomodel, which in fact involves a combined effort between geologist, geophysicist, reservoir engineer and petrophysicist. The saturation-height function presented in this book is based on hydraulic flow unit principle that predicts water saturations above free-water-level away from the well. It can easily be adjusted and used in different fields with little modifications.

A 3D geomodel constitutes a framework of grid-cells that is built using geological understanding of depositional environment guided by seismic attributes to delineate reservoir trends and connectivity. Faults or reservoir pinch-outs are identified and drawn accordingly. Absolute depths of reservoirs are defined in the framework using information from well logs.

Each grid-cell that has well penetration contains information about the reservoir and its fluid distribution that petrophysicist provides. Reservoir parameters that are needed to populate the grid-cells with are fluid type and contact, reservoir thickness, porosity, permeability and water saturation. Determination of each of these petrophysical parameters are explained in subsequent chapters using simple but yet powerful techniques.

2. Basic Petrophysical Parameters for 3D Geomodel

Reservoir properties that are used to populate grid-cells in computing models are porosity (Ø), permeability (k), reservoir thickness and water saturation (S_W).

The choice of using "total" or "effective" porosity systems for volumetric calculations of hydrocarbon-in-place is immaterial because both systems would give the same answer provided the equivalent "total" and "effective" water saturations are consistently used throughout the calculations. A mathematical proof of this is presented in Appendix A.

The advantage of effective porosity ($Ø_E$) is that pore spaces occupied by shale clay-bound water have been discounted for and the porosity value would therefore reflect the true pore spaces occupied by formation fluid (gas, oil or water). Unfortunately, $Ø_E$ is not easily determined because one would have to understand the type, distribution and quantity of clays within the reservoir rocks. Expensive coring and mineralogy measurements are needed to fully characterize these clays and, more often than not, are not readily available.

On the other hand, total porosity ($Ø_T$) is easily calculated from raw logs and it usually matches lab-measured total porosity of cores better. This is a key assertion to make because it is widely accepted that core-derived measurements, viz., $Ø_{Core}$, k_{Core} and P_C, are often used as benchmarks by geoscientists provided all the necessary precautions are taken to ensure these lab measurements are properly carried out. For this reason, the author proposes to work with "total" porosity system in the derivation of SHF and shall hereafter refer to *total* porosity and *total* water saturation as $Ø_T$ and S_{WT} respectively.

Please note that lab measurements on cores should be done under Hydrostatic Confining Stress (HCS) condition and *not* Net Overburden Pressure (NOB). This is sometimes overlooked by operators, which will lead to erroneous core-derived measurements. Please refer to Appendix B for details.

2.1. Porosity

There are three sources of porosity logs available in almost every modern wells, viz., RHOB (ρ_B), NPHI ($Ø_N$) and ΔT (DT) logs, and they are acquired using density, neutron and sonic logging tools respectively. Brief descriptions of the principles of these logging tools are described below.

2.1.1. Density Log

Density tool emits medium energy gamma-rays in the formation and measures the number as well as energy of gamma-rays returning back to the tool. These gamma-rays interact with electrons in reservoirs and naturally the number of electrons is proportional to density of reservoirs and

3. Pressure-Depth Plot

A plot of reservoir pressures versus depth in TVDSS is an extremely useful tool to identify fluid types, contacts, pressure systems and reservoir connectivity. During production life of hydrocarbon fields, acquisition of reservoir pressures from in-fill wells may help understand depletion behaviour and even identify untapped reservoirs.

3.1. Reservoir Pressure

Reservoir pressures can be obtained by running specialized formation pressure tools either on wireline or logging-while-drilling (LWD). These tools have a small probe that is pushed into reservoir rock to establish communication with pressure gauges in the tool via a flowline. A small volume of drawdown is performed and the flowline pressure drops but quickly builds-up to record the reservoir pressure. Descriptions of pressure measurements versus time of a pretest and sampling cycle are shown in Figure 7. A tool schematic of pretest and fluid sampling sequence is shown in Figure 8.

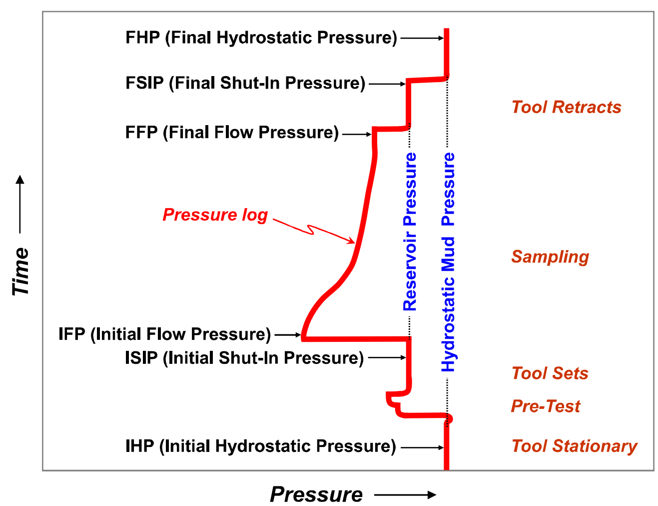

Figure 7: Pressure measurements during a pretest and sampling cycle

4. Types of Formation Fluids

A brief description of various hydrocarbon formation fluids is presented here. It is important for petrophysicists to appreciate this because log signatures are directly affected by the type of hydrocarbons found in reservoirs and any phase changes that might occur to the original reservoir fluid with depletion due to production.

Hydrocarbons found in reservoirs may be broadly classified into five types: black oil, volatile oil, gas condensate/retrograde gas, wet gas and dry gas. Schematic pressure-temperature phase diagrams are used to illustrate differences in phase behaviour of these five hydrocarbon types.

5. Log Signatures and Fluid Interpretation

Identification of formation fluids (water, oil or gas) is arguably one of the most challenging and important tasks for a petrophysicist. Serious financial impact can occur if formation fluid is incorrectly identified.

In spite of the advent of high-speed computing capability and technological advancements in logging tools, there is no “magic” formula or algorithm that can be used to identify formation fluid types. The science just isn’t there yet for us to apply it, unfortunately. In the author’s opinion the reason is pretty simple actually; reservoir rocks and formation fluids are just far too complex and varied for any mathematical model to be used for fluid identification.

Perhaps artificial intelligence (AI) might be able to identify formation fluids in future but we will just have to wait for that day. Statistically speaking, the chances of predicting correctly the formation fluid (water, oil or gas) are rather high at 33.3% and yet until today there isn’t any model or software package that can perform this task. It still requires human interaction using all available data pertinent to the reservoir rock to identify the fluids. Man successfully lands space crafts on Mars some 225 million kilometres away eleven out of fourteen times but struggles to characterise rocks and identify formation fluids barely 2 kilometres beneath our feet.

The oil and gas industry has until now relied on several sources of data and techniques for formation fluid identification. They are as follows:

a) ***Well Logging***

- *Resistivity Log*: Hydrocarbons (oil and gas) are generally more resistive than water. High resistivity readings can indicate the presence of hydrocarbons.
- *Neutron and Density Logs*: These logs measure the hydrogen index and bulk density of the formation. Gas typically shows lower density and lower neutron porosity compared to oil and water for similar quality reservoirs.
- *Spontaneous Potential Log*: The amount of SP deflection from shale baseline is indicative of formation fluid. Water tends to deflect the most while gas tends to deflect the least with oil somewhere in-between but closer to water.
- *Sonic Log*: Sonic tool measures the speed of sound through the formation. Gas usually has a slower sonic velocity compared to oil and water.
- *Nuclear Magnetic Resonance Log*: This can differentiate between different types of fluids based on their relaxation times.

b) ***Production Test***

- *Drill Stem Test (DST)*: This test isolates a section of the wellbore and allows the formation fluids to flow to the surface, where they can be sampled and analysed.
- *Wireline/LWD Formation Testers*: These are specialised downhole logging tools that can take fluid samples directly from the formation and measure in situ pressure and fluid properties.

5.7. Field Examples of Formation Fluid Identification Using Log Signatures

Field examples of formation fluid interpretation using log signatures are found in this section. For each example, detailed narratives are presented to explain the logs' responses to formation fluids. When available, other sources of data are also used to identify and confirm the identification of formation fluids, e.g., pressure data, mud logs, downhole sampling and/or production tests.

5.7.1. Sandstone Containing Water, Oil and Gas

An example of sandstone reservoirs containing water, oil and gas is shown in Figure 27.

NPHI and RHOB logs are plotted in sandstone compatible scales because the reservoirs are clastic rocks as shown in log plot Figure 27(a). In log plot Figure 27(b), RHOB scale is adjusted to shift the log slightly to the left to visually improve log signatures of NPHI-RHOB curves. In addition, compressional (DT) sonic log is displayed in Track 2 for fluid identification. Fluid identifications using the following logs are explained in detail below.

SP log:

In Track 1 of Figure 27(a), SP shale baseline is identified and drawn. The magnitude of SP deflections from shale baseline across four relatively thick and clean sands (Sands A/B/C/D) is measured and are found as follows; $SSP_{Sand\ D} > SSP_{Sand\ C} \approx SSP_{Sand\ B\_Lower} > SSP_{Sand\ B\_Upper} \approx SSP_{Sand\ A}$. Based on the SP deflection magnitudes, it suggest Sand D (22 mV) is water-bearing, Sand C (21 mV) and Sand B-Lower (21 mV) are oil-bearing, and Sand B-Upper (18 mV) and Sand A (17 mV) are gas-bearing. Although the SSP differences are not significant enough for fluid identification with absolute certainty they nonetheless provide initial clues as to the fluid types. More evidences are needed from other log signatures to be certain and are explained below.

NPHI log:

In Track 2 of Figure 27(a), neutron baselines of Sands B_Lower/C/D are the same suggesting they are oil and/or water-bearing. Note the neutron baseline shifts to the right across Sands A/B_Upper indicating that these shallower sands are definitely gas-bearing.

NPHI-RHOB logs:

In Track 2 of Figure 27(b), the left scale of RHOB is adjusted from 1.85 to 1.95 g/cc and this bulk shifts RHOB log slightly to the left. It helps visualise log signature of NPHI-RHOB curves whether they track each other like a railway track or cross-over like a butterfly shape. Clearly, the NPHI-RHOB log signature of Sands A/B_Upper is butterfly shape indicating they are gas-bearing even before the scale adjustment so this trick is rather redundant for these sands. However, the shapes of Sands B_Lower/C/D are now more obvious as a railway track after the scale adjustment indicating they are oil and/or water-bearing.

6. Saturation-Height Function

Saturation-height Function (SHF) is a technique that quantifies the saturation of water in reservoir rocks above FWL based on rock properties and capillary pressure. It is primarily used as inputs in 3D geomodel.

The first step in SHF process is to identify reservoir rocks according to their common characteristics. This process is often referred to as "rock typing". The two most common methods are geological rock typing (facies analysis, litho facies and depositional environment classifications) and characterizing rocks into groups with similar reservoir properties (Global Hydraulic Elements technique, Petrophysical Rock Type, Winland R35 method, Lucia method, Lorenz plots and Statistical Rock Typing). Regardless of the method used, each identified rock type would have its unique capillary pressure curve and its shape would naturally be different in each case.

Having established the different rock types, the next step is to predict these rock types across the entire well using well logs data.

Finally, S_{WT} is calculated for each reservoir using equations that are based on capillarity and height above FWL, and curve fitting these SHF-derived S_{WT} values to log-derived S_{WT}.

In this chapter, the Global Hydraulic Elements technique to delineate reservoir rocks, predict rock types across all intervals, and calculate SHF-derived S_{WT} is presented. It can be easily formulated and used in different fields with minimal modifications. Its simplicity and robustness makes turnaround of SHF work much quicker. This SHF technique is based on hydraulic flow units[1] principles.

6.1. Rock Typing Using Hydraulic Flow Units

Reservoir rocks can be delineated using a concept that describes its capability to fluid flow by Kozeny-Carmen equation. The equation is used to derive permeability as a function of rock attributes. It is originally proposed by Kozeny (1927) and later modified by Carman (1937, 1956) to become the Kozeny-Carman equation. Basically, the equation estimates the permeability of rock based on grain size distribution.

In a 1993 SPE paper that has been widely received by the industry, Amaefule[2] describes a hydraulic (pore geometrical) unit as the representative elementary volume[3] "*of total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from properties of other rock volumes*"[4].

Amaefule modifies the Kozeny-Carmen equation, which allows the identification of these individual rock types or hydraulic flow units as follows:

7. Field Examples of Saturation-Height Function Work

In this chapter, four field examples of SHF works are presented to highlight petrophysical challenges being encountered and how GHE technique is used to mitigate the situations.

7.1. Developing SHF when Core Data is not available

Performing SHF works to predict permeability and determine SHF-derived S_{WT} when core data is *not* available can still be done using modified GHE technique.

To illustrate this, a well that contains water, oil and gas is used as an example. The well penetrates OWC and GOC based on log signatures. Formation pressures are also taken that confirms the fluid types and contacts seen on logs.

7.1.1. Fluid Identification Using Log Signatures

Open-hole logs of the well penetrating sandstone reservoirs are shown in Figure 59.

NPHI (TNPH) and RHOB logs are plotted in sandstone compatible scales because the reservoirs are clastic rocks and this is depicted in log plot Figure 59(a). In log plot Figure 59(b), RHOB scale is adjusted to shift the log slightly to the right to visually improve log signatures of NPHI-RHOB curves. Fluid identifications using the following logs are explained in detail below.

SP log:

Not available since the logs are recorded using LWD tools.

NPHI log:

In Track 2 of Figure 59(a), neutron baselines of sands below 2697.5 m TVDSS are the same but it shifts to the right above that depth indicating the overlying sands are gas-bearing.

NPHI-RHOB logs:

In Track 2 of Figure 59(b), the left scale of RHOB is adjusted from 1.85 to 1.70 g/cc and this bulk shifts RHOB log slightly to the right. This helps visualise log signature of NPHI-RHOB curves whether they track each other like a railway track or cross-over like a butterfly shape. Clearly, the NPHI-RHOB log signature of sands above 2697.5 m TVDSS is butterfly shape indicating they are gas-bearing even before the scale adjustment so this trick is rather redundant for these sands. However, the shapes of sands below 2697.5 m TVDSS are now more obvious as a railway track after the scale adjustment indicating they are oil and/or water-bearing. Now, notice that based on their elevated resistivity readings there are two oil-bearing sands (viz., Oil Sand A and

7.2. SHF is Used to Identify Different Sand Bodies in Horizontal Wells

A vertical exploration well EXP-1 discovers 8 m TVD of oil in a sandstone reservoir called Sand A and the well also penetrates an OWC. The depositional environment of this reservoir consists of distributary channel, muddy coastal plain, sandy coastal plain, silt-filled channel and incised valley fill.

Four horizontal development wells are subsequently drilled to produce the oil from Sand A. However, varying FWLs derived from SHF show that the horizontal wells actually penetrate different sand bodies of channel Sand A, and that they are not connected. These sand bodies therefore belong to different fluid pressure systems. In fact, upon close inspection this finding is also corroborated by log signatures.

Detailed petrophysical evaluations are discussed in the following sub-sections according to chronological order beginning with the exploration well EXP-1 and followed by the four horizontal development wells (HOR 1/2/3/4). These evaluations include formation fluid identification using log signatures, formation pressure, downhole fluid sampling and mud log. A complete SHF work carried out for EXP-1 is also presented including the determination of fitting parameters relating to FZI and SHF-derived S_{WT} using Leverett-J function.

7.2.1. Exploration Well Containing Water, Oil and Penetrated OWC

Sandstone reservoirs named as Sand A and Sand B containing water and oil discovered by an exploration well (EXP-1) are shown in Figure 61.

NPHI and RHOB logs are plotted in sandstone compatible scales because the reservoirs are clastic rocks and this is depicted in log plot Figure 61(a). In log plot Figure 61(b), RHOB scale is adjusted to shift the log slightly to the *right* to visually improve log signatures of NPHI-RHOB curves. Fluid identifications using the following logs are explained in detail below.

SP log:

Not available since the logs are recorded using LWD tools.

NPHI log:

In Track 2 of Figure 61(a), neutron baselines of Sand A and Sand B are identical. This suggests formation fluids in the sands are either water and/or oil. A quick glance at resistivity logs in Track 3 confirms the presence of oil in Sand A with an OWC clearly visible at 1449.3 m TVDSS. Sand B is entirely water-bearing.

NPHI-RHOB logs:

In Track 2 of Figure 61(b), the left scale of RHOB is adjusted from 1.85 to 1.75 g/cc and this bulk shifts RHOB log slightly to the right. This helps visualise log signature of NPHI-RHOB curves

7.3. SHF is Used to Determine Fluid Pressure Systems of Two Oil-Bearing Sands

The logs in this example are the same as in Section 5.7.12. To recap, there are two sandstone reservoirs called Sand A and Sand B. Sand A is proven to be oil-bearing based on RFT sample while Sand B contains only oil but is misinterpreted by the operator as having gas in the upper and lower parts of the sand. As discussed, log signatures indicate the entire Sand B to be oil-bearing instead. However, the overlying oil-bearing Sand A appears to be in a separate fluid pressure system from Sand B based on a 4 psi pressure shift from pretest measurements. The pressure shift suggests FWLs of Sand A and Sand B should be different. Water-legs of both sands have not been penetrated by any wells.

In this section, SHF using modified GHE technique is used to determine the FWLs of Sand A and Sand B, and to ascertain whether the sands are in different fluid pressure systems as suggested by the 4 psi shift in pressure measurements.

Open-hole logs are plotted in Tracks 1, 2, 3 of Figure 70 and log-derived $Ø_T$ and S_{WT} are plotted in Tracks 4, 5, 6 as *blue* curves. Pressure-depth plot of formation pressures taken in these reservoirs are shown in the right and are drawn to scale in m TVDSS with the log plot.

In the absence of core data, fitting parameters that are needed to predict permeability utilizing GHE-modified reservoir delineations (see PERM_GHE log in Track 7) and to calculate SHF-derived S_{WT} logs using Leverett-J function (see SW_J-Function logs in Tracks 5 and 6) are taken from similar oil sands in a nearby field. Only the FWL parameter is changed for this exercise.

In Tracks 5 and 6, SHF-derived S_{WT} logs using Leverett-J function and utilizing GHE-modified reservoir delineations are displayed as *orange* and *red* curves respectively. The *orange* SHF-derived S_{WT} log in Track 5 is determined by matching SHF-derived S_{WT} with *blue* log-derived S_{WT}. In order to achieve this, Sand B would have to be broken up into several sections with different FWLs as illustrated. Notice that these sections are separated by shale-breaks, which indicate they are separate sand bodies stacked on top of each other, and they are therefore not in pressure communication. The varying FWLs between Sands A and B means they are indeed in separate fluid pressure systems as suggested by the 4 psi pressure shift in pressure measurements.

To confirm the above findings, Sand A and Sand B are now assumed to be in the same fluid pressure system with a single FWL of 1620 m TVDSS. The SHF-derived S_{WT} log for this case is calculated and plotted in Track 6 as *red* curve. Notice that the SHF-derived S_{WT} log (*red*) and log-derived S_{WT} log (*blue*) do not match across several intervals highlighted by *black* ellipses indicating the assumption that Sand A and Sand B belong to the same pressure system is incorrect.

This example demonstrates how SHF helps to establish, not only the fluid pressure systems of Sands A and B, but predicts FWLs of the oil sands too even when no wells have penetrated any of their water-legs. It is no longer necessary to drill appraisal wells to test for water contacts as is usually done in the past. This is a powerful technique that can be used to plan well trajectories to target oil-bearing sands and avoid water-legs.

7.4. FWL Predicted from SHF Debunks FWL Obtained from Pressure Data

An exploration well EXP-1 discovers gas in Sand A. The operator subsequently drills a side-track well EXP-1 SDTR slightly downdip of the original hole to chase for its oil column and finds a GOC at 1137.2 m TVDSS in the sand. A second exploration well EXP-2 targeting Sand A further downdip unfortunately finds it to be completely water-bearing. A third exploration well EXP-3 finds Sand A to be poorly developed on the other side of an anticline. Pretests are taken in the wells and formation fluid gradients are established. From the intercept of oil and water gradients, a FWL is found to be at 1183.5 m TVDSS, which gives an encouraging thick oil column of 46.3 m TVD. Based on these seemingly straightforward results, a field development plan to develop the oil in Sand A is completed and the project is just about to be sanctioned.

Profiles of these exploration wells are plotted on a seismic cross-section in Figure 71.

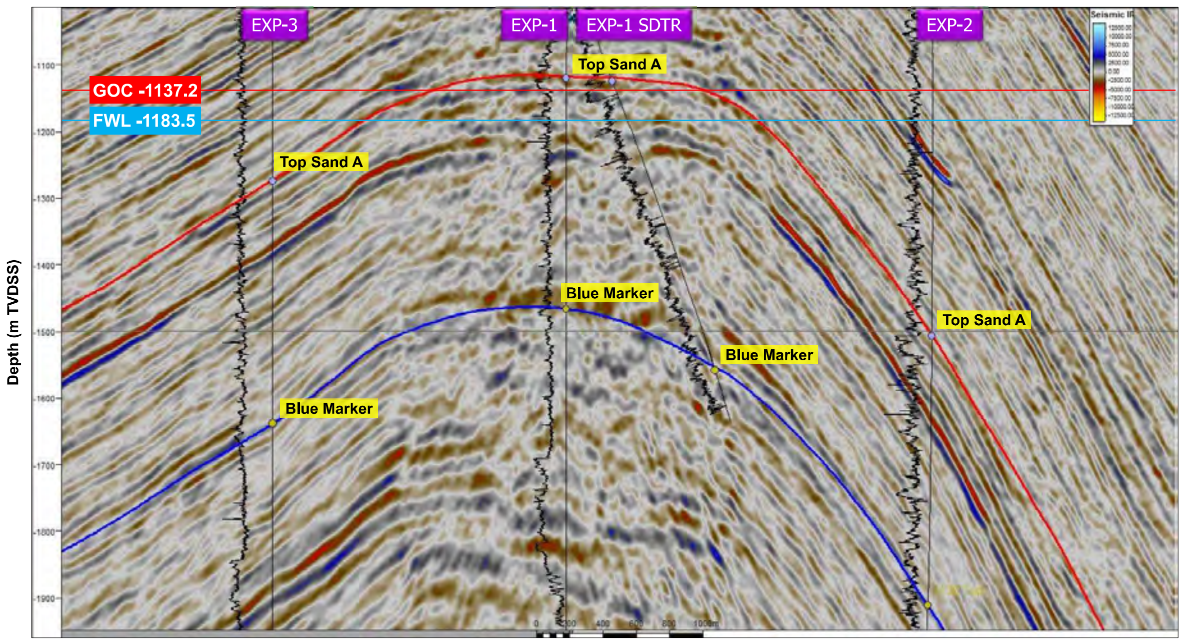

Figure 71: Profiles of exploration wells plotted on a seismic cross-section

Fortunately, a SHF study is carried out to predict the FWL using modified GHE technique and SHF-derived S_{WT} equation using Leverett-J function. The FWL is instead found to be much shallower at 1160 m TVDSS. The oil column is reduced to 22.8 m TVD, which makes the project uneconomical.

The development plan is suspended and an open-water appraisal well is drilled to test the oil column. As it turns out, the 46.3 m TVD oil column isn't there. The project is cancelled and a potentially expansive project failure is averted.

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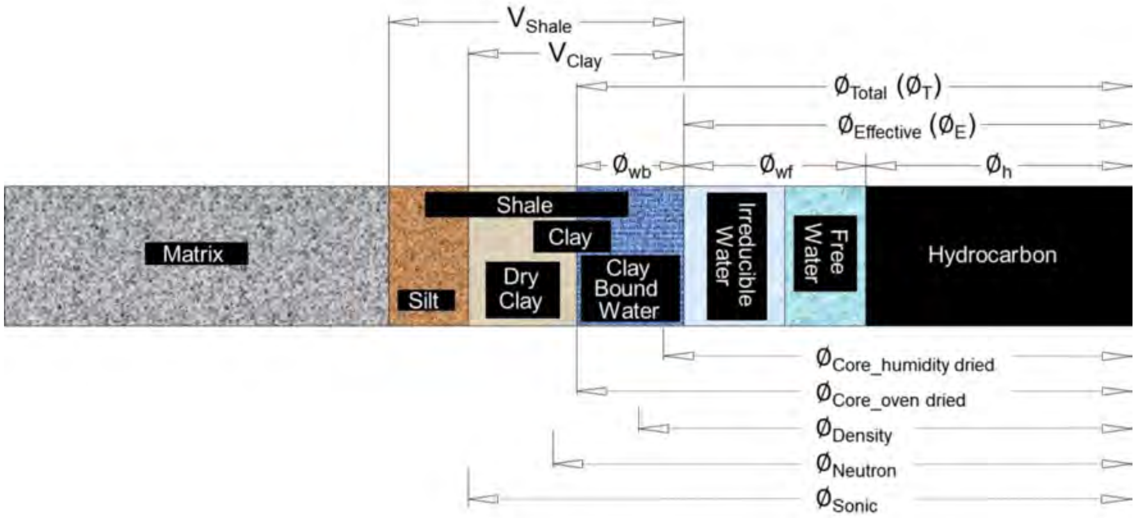
Appendix A: "Total" and "Effective" Porosity Systems in Petrophysics Domain

Porosity is an important parameter in the hydrocarbon-in-place equation. It is often defined as the total pore spaces occupied by hydrocarbons or water regardless whether they are mobile or immobile.



A reservoir rock may be modelled simply by its matrix, shale and pore spaces as illustrated above. This rock model assumes there are three types of water in the reservoir:-

1) *Clay Bound Water* – includes both water held to the net-negatively charged clay mineral surfaces and the water of hydration associated with the mineral charge balancing counter-ions.
2) *Irreducible Water* – is immobile water held by capillary forces in regions of micro-porosity, for example, dead-end pores and pendular rings.
3) *Free Water* – is water that is able to flow under a given pressure gradient.

In this model, total porosity ($\varnothing_T$) is defined as the volume occupied by hydrocarbon, free water, irreducible water and clay bound water. Effective porosity ($\varnothing_E$) is defined as total porosity minus volume of clay bound water. However, there are no tools available that measure either porosity directly. Please see estimated ranges of volumes being measured by $\varnothing_{Core}$, $\varnothing_{Density}$, $\varnothing_{Neutron}$ and $\varnothing_{Sonic}$ annotated at the bottom of the above diagram.

For volumetric purpose, it is obvious that $\varnothing_E$ would be the preferred choice for hydrocarbon-in-place calculation, viz., OIIP (Oil Initially In-Place) and GIIP (Gas Initially In-Place). In order to calculate $\varnothing_E$ from raw logs the challenge is to determine type of clays, its distribution and quantity in the reservoir rock. Although these can be found from core analysis but they are often not readily available and do not cover all reservoirs of interest.

Appendix B: Hydrostatic Confining Stress (HCS) and Net Overburden (NOB) Pressure

All core samples in the lab must be subjected to Hydrostatic Confining Stress (HCS) pressure and *not* Net Overburden (NOB) pressure. This is sometimes overlooked by operators, which will lead to erroneous core-derived measurements, viz., $\varnothing_{Core}$, k_{Core} and P_C.

Anisotropic stress exerted on reservoir rock is such that:

$$\sigma_V > \sigma_{H\,max} > \sigma_{H\,min}$$

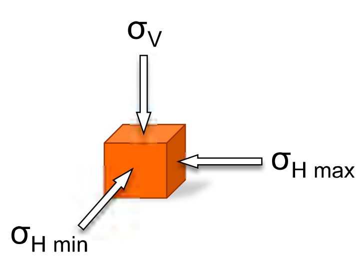
where,

σ_V = Total Vertical Stress

$\sigma_{H\,max}$ = Maximum Horizontal Net Stress

$\sigma_{H\,min}$ = Minimum Horizontal Net Stress

The anisotropic stress may be illustrated with normal stresses acting on the faces of an elemental reservoir cube as shown below.



The total vertical stress, σ_V, is the Overburden Pressure. It is a function of the bulk density of rock (ρ_B) from surface down to the point of interest. The magnitude of σ_V gradient is approximately 1 psi/ft.

Reservoir pore pressure (P_R) acts to decrease the total vertical stress. So the effective vertical stress or the Net Overburden Pressure (NOB) the rock feels is:

$$NOB = \sigma_v - P_R$$

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