GeoFit™ PETROPHYSICS

GeofitPetrophysics_WHP_ALL_201810168_REV00

Revision History

Documents are reviewed annually to ensure relevance to the systems and process that they define.

Rev	Date	Originator/Reviser	Dept	Reason for Change
0.0	10 - 2018	Jouve, N.		
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Petrophysics as a Discipline

Petrophysics is the study of physical and chemical rock properties and their interactions with fluids. A major application of petrophysics is in studying reservoirs for the hydrocarbon industry. Petrophysicists are employed to help reservoir engineers and geoscientists understand the rock properties of the reservoir, particularly how pores in the subsurface are interconnected, controlling the accumulation and migration of hydrocarbons. Some of the key rock properties studied in petrophysics are lithology, porosity, water saturation, permeability and density. A key aspect of petrophysics is measuring and evaluating these properties by acquiring well log measurements – in which a string of measurement tools are inserted in the borehole, core measurements – in which rock samples are retrieved from subsurface, and seismic measurements. These studies are then combined with geological and geophysical studies and reservoir engineering to give a complete picture of the reservoir.

Figure 1 provides a summary of typical reservoir properties evaluated by petrophysicists and possible sources or tools used to characterize them. At the wellbore scale, several techniques are applied to understand rock and fluid properties. At the reservoir scale, the variation of the reservoir porosity, permeability, and saturation are typical issues often investigated by engineers.

Reservoir Property	Primary Tool	Secondary Tool
Thickness (Bed Boundaries)	Gamma Ray log/ Borehole Image	Electric Log with SP
Lithology/Rock Type	Core	Mud Log/Spectroscopy logs
Porosity	Density and Neutron log	Core
Saturation (Oil, Gas, Water)	Electric log	Carbon-oxygen log
Fluid Characterization	Formation Tester	Mud Log
Permeability	Core	Formation Tester
Fractional Flow	Core	Formation Tester

Figure 1. Possible sources/tools choices for particular reservoir properties.

In Petrophysics, the scale plays a key role in identifying a potential reservoir (**Figure 2**). Core analysis can look at micrometer scale objects when seismic data will a scale up to hundreds of metres.

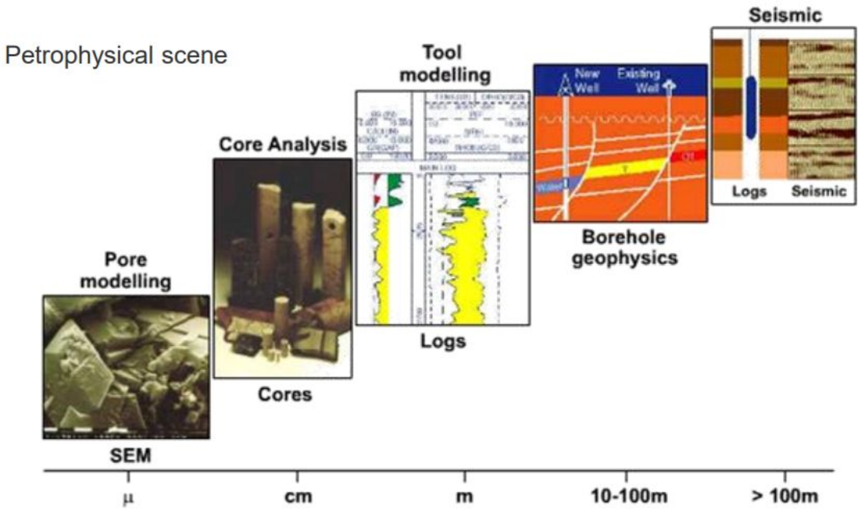

Figure 2. Different Scales associated to the different sources[1].

Quick Look: GeoFit™ Approach

Drilling a well is a complex operation. Data collection, such as logging while (wasn't sure what you were trying to say?) drilling or mudlogging data, is a significant investment but mandatory to monitor well progress and ensure safe operation. Gathering of Geological data is especially important in exploration and appraisal wells, which are drilled for the sole purpose of obtaining information on the subsurface. The basic Quick Look interpretation method gives an efficient and relatively accurate method to analyze the logging data at the wellsite by visual inspection of the raw data.

In GeoFit™, it is expected that t data cleaning is done prior to the start of the Quick Look workflow.

Figure 3 provides a snapshot of typical quick look analysis.

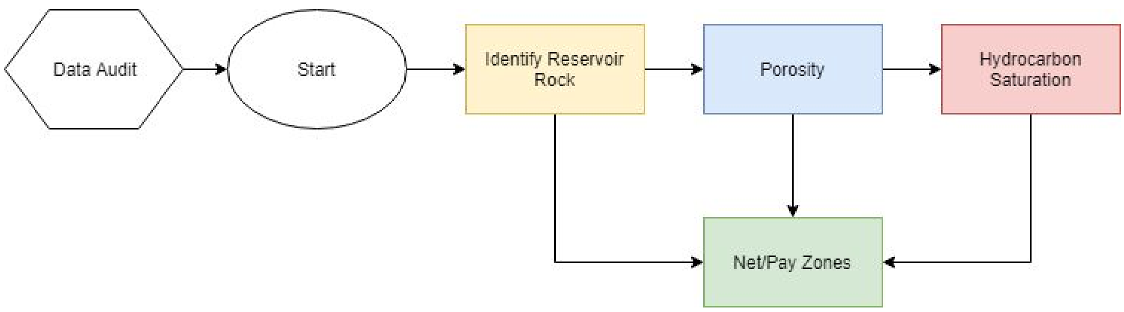

Figure 3. GeoFit™ Quick Look Workflow

[1] https://www.uio.no/studier/emner/.../6-introduction-to-petrophysics-august-2015.pdf

Conventional Petrophysical Analysis: GeoFit™ Approach

Shale Volume

In shaly sand carbonate reservoirs, the shale fraction is the fraction of the rock containing fine grained material and consisting of clay and silt-sized particles. Shale contains clay minerals as well as particles of quartz, feldspar, mica, iron oxide and organics and other minerals, and includes the water bound to the shale constituents.

Porosity

The calculation of porosity is paramount as it determines the ultimate volume of a rock type that can contain hydrocarbons. The value and distribution of porosity, along with permeability and saturation, are the parameters that dictate reservoir development and production plans.

Determination of porosity from a wireline log is only part of the problem, as values determined in one well must be upscaled into the space between wells. To extrapolate correctly, the team must identify depositional environments and rock types,then have access to analog data sets. Only then can the correct statistical distributions be extrapolated across the reservoir.

Fluid Saturation

The determination of in-situ oil, gas, and water saturations relies on interpretations of logging devices that read far from the borehole and from any fluid alterations caused by invasion during drilling.

Water saturation determination is the most challenging of petrophysical calculations and is used to quantify its more important complement, the hydrocarbon saturation. Complexities arise because there are a number of independent approaches that can be used to calculate Water Saturation. The complication is that often, if not typically, these different approaches lead to somewhat different Water Saturation values that may equate to considerable differences in the original oil in place (OOIP) or original gas in place (OGIP) volumes. The challenge to the technical team is to resolve and to understand the differences among the water saturation values obtained using the different procedures in order toarrive at the best calculation of water saturation and its distribution throughout the reservoir vertically.

Permeability

Permeability refers to the ease with which fluids flow through any substance. It is not sufficient to have oil or gas in a formation; the hydrocarbons must be able to flow from the reservoir into the wellbore in order to be recovered at the surface. Absolute permeability is a physical characteristic of the rock. Permeability of a rock for oil, gas, or water is a function of the absolute permeability and the viscosity of the fluid.

A standard workflow to estimate permeability is to make measurements on core samples and to determine permeability with the methods available in GeoFit™.

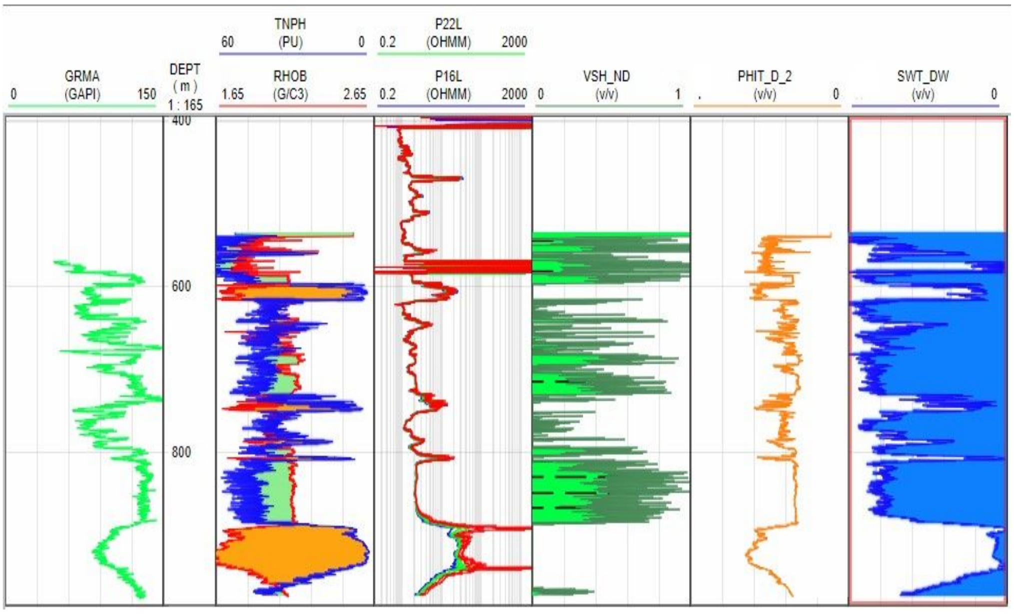

Figure 4. Petrophysical interpretation in GeoFit™

Unconventional Petrophysical Analysis: GeoFit™ Approach

Unconventional reservoirs are those reservoirs which have low permeability and effective porosity, making themdifficult to produce by conventional methods. Identification of these reservoirs are difficult as these show more affinity to shale than sandstone or limestone on log character. Sometimes these are misinterpreted as shale. Due to this character, quantification of porosity and water saturation in these reservoirs is also challenging. Generally, special logs like NMR and core measurements are not available to properly evaluate such reservoirs. Derivation of porosity is very difficult in absence of core measured grain density, particularly when lithology is predominantly shale/silt with varying grain density.

TOC Calculation

To understand the petrophysical properties of an unconventional reservoir, well log data is used to investigate the rock properties of shales in the areas of interest. Petrophysical evaluation comprises quality checking and editing of the available well logs. Additionally, the description of rock properties, evaluation of the intervals of interest, and calculations to estimate the shale or clay volumes and the TOC (Total Organic Content).

Passey Method [2]

Assuming that resistivity logs respond to fluids, while porosity logs (sonic, density, or neutron) respond to kerogen/matrix and fluids, the Passey method combines these two type of logs to estimate TOC in organic-rich rocks. Using as either a porosity curve or a porosity log, the method relies on porosity and deep resistivity readings separating from each other in organic-rich rocks, whereas in organic-lean rocks, the two curves overlie. The separation between the two curves or the scaled difference (ΔlogR) between them is related to the TOC through the level of thermal maturation.

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[2] Passey, Q.R., Creaney, S., Kulla, J.B., Moretti, F.J. & Stroud, J.D. (1990). A pratical model for organic richness from porosity and resistivity logs. *AAPG Bulletin, 74, 12, 1777-1794*

Schmoker Method [3]

Assuming that the change in density of the formation is due to the presence or absence of low-density organic matter, an empirical approach was developed by Schmoker (1979) to quantitatively estimate TOC in Devonian shales from log data. The methodology was then refined for the Bakken black shales which were treated as a four-component system consisting of rock matrix, interstitial pores, pyrite, and organic matter. High-density minerals other than pyrite are assumed to comprise a fixed (but unknown) percentage of the rock matrix.

Kerogen Volume

Organic material can be classified according to the source of the material, as shown below.

Types of Kerogen and Their Hydrocarbon Potential

Environment	Kerogen Type	Kerogen Form	Origin	HC Potential
Aquatic	I	Alginite	Algal bodies	
Aquatic	I	Amorphous Kerogen	Structureless debris of algal origin	Oil
Aquatic / Terrestrial	II	Amorphous Kerogen	Structureless planktonic material, primairly of marine origin	Oil
Terrestrial	II	Exinite	Skins of spores and pollen, cuticle of leaves and herbaceous plants	Oil
Terrestrial	III	Vitrinite	Fibrous and woody plant fragments and structureless, colloidal humic matter	Gas, some oil Mainly gas
Terrestrial	IV	Inertinite	Oxidized, recycled woody debris	None

Type I kerogen is hydrogen rich (atomic H/C of 1.4 to 1.6: HI of > 700) and is derived predominantly from zooplankton, phytoplankton, micro-organisms (mainly bacteria) and lipid rich components of higher plants (H/C ratio 1.7 to 1.9).

3 Schmoker, J.W. (1981). Determination of organic-matter content of Appalachian Devonian shales from Gamma-ray logs. *AAPG Bulletin, 65, 7, 1285–1298*

Type II kerogen is intermediate in composition (H/C ≈ 1.2: HI ≈ 600) and derived from mixtures of highly degraded and partly oxidized remnants of higher plants or marine phytoplankton.

Type III kerogen is hydrogen poor (H/C ratio 1.3 to 1.5) and oxygen rich and is mainly derived from cellulose and lignin derived from higher plants.

Type IV kerogen is hydrogen poor and oxygen rich and essentially inert. This organic matter is mainly derived from charcoal and fungal bodies. Type IV kerogen is not always distinguished but is grouped with Type III.

The different types of organic matter are of fundamental importance since the relative abundance of hydrogen, carbon, and oxygen determines what products can be generated from the organic matter upon diagenesis. Since coal is comprised predominantly of Type III kerogen, there is little liquid hydrogen generating capacity.

Kerogen volume is difficult to measure directly but can be inferred from a plot of (inverse) core grain density versus TOC weight percent or mass fraction. This value is needed to find kerogen volume fraction from kerogen weight fraction. The method also relies on the density versus TOC crossplot