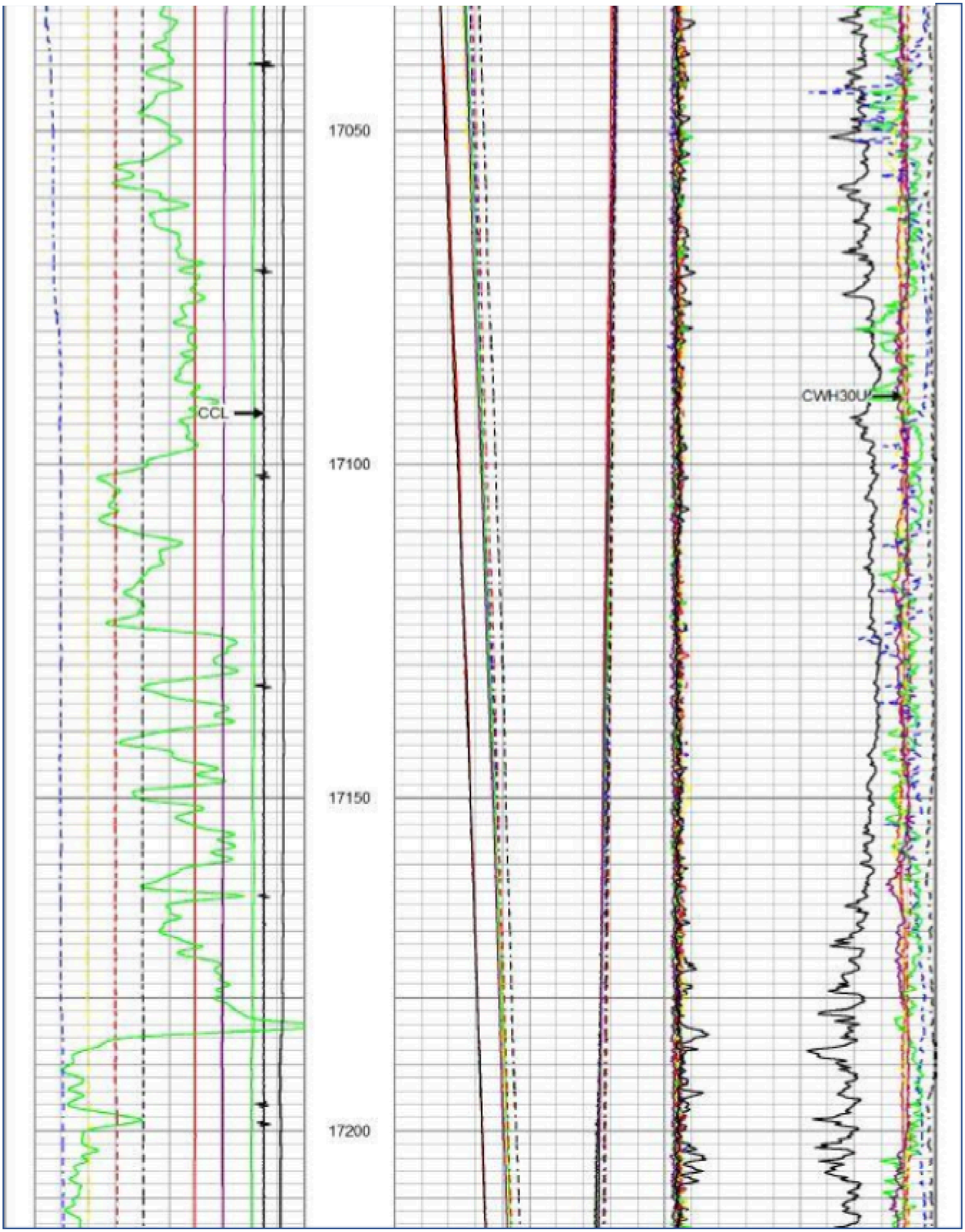
Chapter 1 - The Reservoir and the logging environment



Content

Chapter 1 - The Reservoir and the Logging Environment

Why do clients call a service company to log their wells? Why are standard services (i.e., triple-combo or quad-combo) sufficient for some, but others require more advanced services like imagers or formation testers? How does the borehole fluid influence measurements that supposedly are used to represent formation properties? Does filtrate invasion influence log responses? What information is the client trying to determine from wireline logs, and what is this information used for?

All of these questions (and the many more that will follow) are important considerations to professionals in the field because each one of them is somehow related to the client's primary concern with the logs: data quality. By knowing something about the physical properties of rocks and the other factors that influence wireline logging measurements, the importance of data quality in the client's use of these measurements becomes more evident.

Fundamental Formation Properties

The basic purpose behind logging triple-combo or quad-combo services is to provide the client with their "first look" at fundamental properties that are vital for evaluating the potential producibility of a hydrocarbon reservoir. These properties include:

1. Lithology
2. Porosity
3. Fluid saturations
4. Permeability

While there are many more properties of interest, a basic evaluation of the formation can be made with knowledge of just these four. Additional information, which means more logs, requires additional investment on the part of the client. The field professional of the service company, however, is rarely involved in formation evaluation. Their job is data acquisition. Final decisions are usually taken by the representatives of the operator company. Still, a working knowledge of these properties is important for understanding why wireline logs respond the way they do, and for determining the validity of those responses.

Lithology

Lithology relates to both the mineralogy and framework of a rock; in other words, its chemistry and structure. In a very basic sense lithology refers to the type of rock, but a common name for a rock might be too ambiguous. For example, when we call a rock “sandstone,” what does it mean? The term “sandstone” simply implies the rock is composed of sand-sized particles, but says nothing about the rock’s chemistry. Conversely, “limestone” says a great deal about the rock’s chemistry, but absolutely nothing about its structure.

We very quickly get into the habit of referring to rocks as sandstone, limestone, dolomite, etc., and might put little thought to the possibility that different minerals present in such rocks have differing effects on wireline logs. Unfortunately, rocks are very rarely pure. Instead, they contain a number of different minerals in varying percentages, each of which has a different influence on log response. (The very definition of a rock is something that contains more than one mineral.) Many sandstones contain a large percentage of the mineral quartz (SiO_2), while others might contain equally large percentages of feldspar minerals. The log responses of these two sandstones will be different. Limestones are composed mainly of the mineral calcite ($CaCO_3$), but they might contain a significant fraction of quartz. Dolomites ($CaMg(CO_3)_2$) can contain large percentages of evaporite minerals such as anhydrite. Mineralogy refers to the assemblage of different minerals in a rock that determines its chemical properties which, in turn, influences nuclear logs (i.e., gamma ray, neutron, density). In some types of rocks, mineralogy also influences resistivity logs (e.g., where conductive clay minerals or metallic minerals are present).

Framework describes the physical structure of a rock and determines the distribution of any void space. Is the void space interconnected and capable of allowing fluid to pass through it? Or is the void space isolated, in which case fluids cannot flow? Granular rocks such as sandstone often contain a large percentage of interconnected voids, and the same might be true of granular limestone or crystalline rocks like dolomite. However, some rocks—particularly limestones—can be very dense and massive, and might contain very little, if any, interconnected void space. Whereas the nuclear measurements are sensitive to the mineralogy of a rock, acoustic and resistivity measurements are more sensitive to the framework of the rock. The preferred path of travel for acoustic energy is through a fast matrix instead of slow pore fluids. Current flow created by a resistivity tool prefers conductive fluids (e.g., water) as opposed to non-conductive matrices. Therefore, the framework of a rock influences log responses just as much as the rock's mineralogy.

Knowing something about the lithology of a formation is critical for a variety of reasons. Both geologists and reservoir engineers use this information to streamline future exploration efforts and to optimize production. Some potential applications of lithology information include the following:

• Lithology can provide clues about what to expect in terms of the distribution of void space and whether or not it is interconnected.

• Lithology is useful for reconstructing depositional environments which are instrumental in determining the locations of future wells.

• Lithology is critical information in the design of reservoir stimulation programs such as hydraulic fracturing and acidizing, and also for certain production concerns such as sand control and clay stabilization.

• Lithology is necessary information for selecting computation parameters used to evaluate a reservoir's productive potential, particularly where core samples are not available.

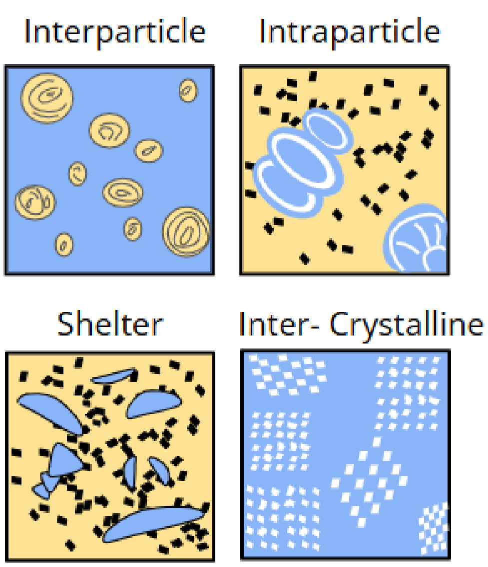
Porosity

Porosity (denoted by the Greek letter Φ) refers to the fractional volume of void space in a bulk volume of rock. For example, if one-quarter of the volume of a rock is open void space, then its porosity is 25%. The primary importance of porosity is that open void space in a rock contains fluids (both water and, hopefully, hydrocarbon). The greater the porosity of a formation, the larger the volume of fluid it contains. Porosity estimates can be obtained from such standard services as neutron, density and acoustic logs.

In addition to the amount of porosity, we must also be concerned with the distribution of porosity. The current caused to flow through formations by wireline resistivity tools travels only through conductive water which, obviously, occupies pore space. The resistivity measured is a function of the length of current flow through this water; therefore, the shape or distribution of pore space in part determines the resistivity responses we observe. Furthermore, fluids existing in the pore space can only flow if those pores are interconnected. Where there is no interconnectivity between pores, the fluids contained within them cannot be produced.

Geologists often refer to porosity as either primary or secondary, which implies the time at which pore space was created. Primary porosity (Fig. 1), for example, is that which was created when sediments were deposited. A good example of primary porosity is the interconnected pore space that exists between grains of quartz or feldspar in a sandstone. Porosity can also be created after sediments are deposited, and is often the result of some process that involves fracturing or dissolution of the rock. This type of porosity geologists refer to as secondary porosity (Fig. 2).

Figure 1. Examples of primary porosity in sedimentary rocks. Pore space shown in blue. (source)



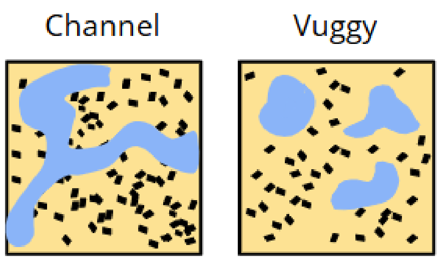
Interparticle: Voids existing between grains

Intraparticle: Voids existing within a grain, clast, or fossil fragment

Intercrystalline: Voids existing between any crystalline grains (such as dolomite)

Shelter: Voids created when sediment is prevented from being deposited by some other grain, clast, or fossil

Figure 2. Examples of secondary porosity in sedimentary rocks. Pore space shown in white. (source)



Dissolution vugs: Large voids created by the dissolution of matrix.

Dissolution channels: Large voids created by the continued dissolution of vugs or along fractures.

The time at which pore space was created makes no difference to a logging measurement. The fact is that the pores exist, and the tools respond to it. Our concern is whether or not the pores are interconnected, because interconnected pores can allow fluid to flow between them. Isolated pores cannot. Total porosity (Φt) refers to the total amount of pore space present in a formation. Effective porosity (Φe) refers only to that amount of pore space which is interconnected and which has the capability of transmitting fluids. The amount of isolated porosity can be estimated by taking the difference between total porosity and effective porosity. Neutron and density logs, because they are sensitive to mineralogy which can be thought of as a bulk rock property, provide estimates of total porosity. Estimates of effective porosity can be obtained from acoustic logs which are more sensitive to the rock's framework.

What is important to realize here is that porosity can only be measured if a core sample is available. Neutron, density and acoustic logs only provide estimates of porosity based upon carefully selected assumptions about the lithology of the formation and the type of fluid contained in its pores. However, two estimates are better than one; therefore, it is common to log two porosity services (e.g. neutron and density) to have a more accurate estimate of the total amount of pore space present. Where the client is concerned about the possibility of isolated pore space, the acoustic porosity estimate becomes important.

Porosity estimates obtained by logs are among the most critical "measurements" provided to the client. Not only do these estimates reflect how much fluid the formation contains and whether or not this fluid might possibly flow through those pores, it is also important for the following applications:

• Porosity, together with resistivity, can be used to estimate how much water and, therefore, how much hydrocarbon exists in the pore space.

• Porosity, together with other information, can be used to estimate volumetric hydrocarbon reserves.

• Porosity is necessary information for selecting computation parameters used to evaluate a reservoir's productive potential, particularly where core samples are not available.

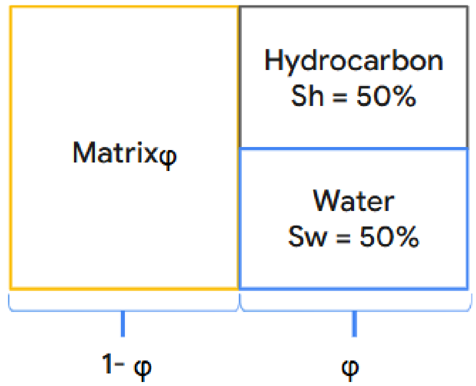
Fluid Saturations

Perhaps the main interest a client has about a formation is if it contains economic quantities of hydrocarbon. Pore fluids include both hydrocarbon and water, so porosity estimates provide an idea of the amount of total fluids present. The problem is, wireline logging resistivity tools cannot measure hydrocarbons.

Oil and gas, just like rock matrix, are electrical insulators. Any current flowing through a formation travels through conductive water existing in the pore space. If we have a resistivity measurement and an estimate of the formation's total porosity, then we can determine what fraction of the pore space is occupied by water. Our assumption, then, is that any pore space not occupied by water must be occupied by hydrocarbons.

Every porous rock contains at least some volume of water. Some rocks, in fact, contain only water; however, no rock contains only hydrocarbons. Hydrocarbon reservoirs actually contain different fluid types in their pores, and saturations refer to the relative proportions of these different fluids (Fig. 3). Water saturation (Sw) is the fraction of pore space occupied by water, and hydrocarbon saturation (Sh) is that fraction occupied by oil and/or gas. (The sum of Sw and Sh must, therefore, equal to 1.0). Conductive water in the pore space supports current flow, so we can use a measure of resistivity together with an estimate of porosity to determine water saturation.

Figure 3. Fluid saturations refer to the fraction of porosity occupied by a certain type of fluid.



The problem with fluid saturations is that they only tell us the relative proportions of different fluids existing in the pore space of the formation. They do not necessarily provide an indication of the relative proportions of these different fluids that will be produced. For example, a water saturation of 25% does not mean that 1 barrel of water will be produced for every 3 barrels of oil. Instead, it only indicates that one-quarter of the formation's pore volume is occupied by water and the other three quarters is occupied by oil. At least some volume of water present in the pores will be irreducible ("bound water"), meaning it is trapped by surface adhesion or capillary forces and cannot be produced. Some oil might also be incapable of being produced, held in place by capillary forces or because of low viscosity.

Using porosity estimates together with resistivities measured at multiple depths of investigation, it is possible to determine water saturations at different distances from the borehole. A comparison of these saturations reveals if hydrocarbon was moved during the invasion of mud filtrate. If the hydrocarbon present is dead oil that cannot be displaced by filtrate invasion, then water saturations at different distances from the borehole are equal. However, if moveable hydrocarbons were displaced by filtrate during invasion, then this is reflected by unequal water saturations at different distances from the borehole. Any hydrocarbon moved during filtrate invasion is assumed to be producible hydrocarbon.

Regardless of the fact that fluid saturations do not necessarily provide good indications of the volumes or proportions of different fluids that will be produced from a formation, they do provide the first indication of whether or not a formation is worth considering as a potential reservoir. Based on fluid saturation estimates and other indicators observed on logs, the client might be able to decide rather quickly if the well should be completed or abandoned. Therefore, fluid saturation estimates become one of the most critical factors in determining the life of a well.

Permeability

With resistivity measurements and porosity estimates, clients can determine both the total amount of fluid present in the formation, the fraction of this total amount of fluid that is water (and hydrocarbon), and if any hydrocarbon is moveable. So, it is possible to use nothing more than triple or quad-combo logs to determine if a formation contains an economic quantity of hydrocarbons. The question now is: can that hydrocarbon be produced?

Permeability refers to a rock's ability to transmit the fluid it contains, and is a requirement for the production of hydrocarbons (and water, for that matter). The unit of measure for permeability is the darcy, which is the permeability of a porous rock that will allow a flow rate of 1 mm per second of a fluid of 1cP viscosity through a 1cm2 cross-sectional area under a pressure gradient of 1 atm/cm. Permeability is often expressed in units of millidarcies (1/1000th of a darcy). Absolute permeability (ka) is a measure of the rock's ability to transmit a fluid through its interconnected pore space when that fluid is at 100% saturation. In other words, absolute permeability refers to a rock's ability to transmit only a single fluid.

Rocks in which our clients are interested contain more than one type of immiscible fluid—water and hydrocarbon. With two immiscible fluids present within interconnected pore space, one will impede the flow of the other. Effective permeability (ke) is a measure of the rock's ability to transmit one fluid when in the presence of another. This ability depends not only upon the rock's absolute permeability, but also upon capillary pressure and the relative amounts (or saturations) of fluids present. The larger the fraction of water occupying the pore space, the more difficult it is to transmit hydrocarbons, and vice versa.

Many logging measurements respond to permeability, but none provides a quantitative measure of permeability. This means that, from logs, an accurate value of permeability cannot be determined. Permeability can only be measured from core samples. However, we can use conventional log responses to determine whether or not permeability exists. These qualitative indicators include SP curve deflections and the separation of resistivity curves showing multiple depths of investigation. Knowledge of lithology and porosity of a rock can also help predict whether there is a chance of the formation being permeable. For example, a sandstone at 30% porosity very likely has a great deal of permeability. In carbonates, however, we might be more concerned with the possibility of low permeability resulting from isolated pore space. More advanced services like formation testers and magnetic resonance logging tools provide better estimates of permeability which, in ideal situations, can closely approximate the rock's permeability.

What other factors influence log responses besides just the rock? What about the borehole fluid and its influence on the accuracy of measurements intended to reflect formation properties? What about the influence of drilling fluid that has invaded a permeable rock and now co-exists in the pore space with original formation fluids? How severe might these influences be, and are logs corrected for them? Again, these are all important questions when considering data quality and the applications of logging measurements.

The Borehole Influence

Logging measurements are acquired by sensors on toolstrings in the borehole; therefore, we cannot escape from the likelihood that borehole properties will have some degree of influence on those measurements. Some tools (e.g., density, microresistivity tool) use pad-mounted sensors in an effort to eliminate or at least minimize the borehole influence. Still other measurements (e.g., resistivity, neutron, gamma ray) are acquired from sensors that are surrounded by the borehole fluid.

For resistivities acquired at multiple depths of investigation, the borehole influence is more severe on shallow measurements than on deep measurements. The magnitude of this influence changes with borehole fluid salinity and borehole diameter. Provided that a resistivity tool is logged in its preferred borehole environment, the influence of the borehole on its measurements is minimal, but very rarely is any tool logged in the "ideal" borehole environment. Fortunately, it is possible to determine the severity of the borehole influence and correct for it. To do this requires that we control tool position by using stand-offs or centralizers, and also that we have measurements of borehole fluid salinity and borehole diameter.

Neutron and gamma ray measurements are influenced by the attenuating effects of the borehole fluid: a larger volume of borehole fluid surrounding the tool results in fewer neutrons and fewer gamma rays reaching the detectors. Increasing borehole fluid density has a similar effect. Correcting for this influence requires a measure of borehole diameter and mud weight. The pad-mounted sensor design of the density tool utilizes collimated and shielded detectors to mostly eliminate the borehole influence.

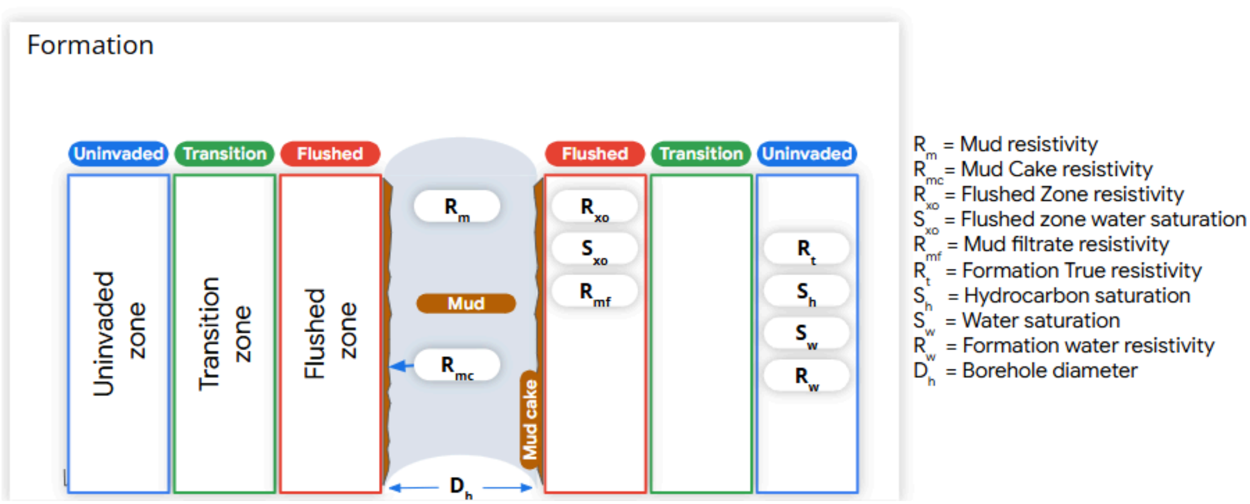
Depending upon how severe the borehole influence, corrections can be applied if borehole properties are known. In making these corrections, the client obtains more accurate estimates of formation properties from our logs. However, only in certain cases are these corrections applied realtime. For most services, borehole corrections are left to the discretion of the client, and logs from service companies provide uncorrected results. Still, you must be able to recognize the effects of the borehole before you can correct it.

Filtrate Invasion

Invasion refers to the process during which pores of a permeable rock are infiltrated by the liquid component—or mud filtrate—of the drilling fluid. Any solid particles in the drilling fluid accumulate as mudcake on the borehole wall adjacent to a permeable formation. Filtrate invasion not only requires that the rock contain interconnected (i.e., effective) pore space, but also that there be a pressure differential across the borehole wall. When hydrostatic pressure in the borehole is maintained above formation pressure ("overbalanced" drilling conditions), filtrate invasion will occur.

The reason why invasion is so important to understand is because it creates a distribution of different fluid types in the formation (Fig. 4). Close to the borehole, the pore space of an invaded formation contains a large proportion of mud filtrate. This region of the formation extends only several inches from the borehole wall and is known as the flushed zone, which implies that original pore fluids have been displaced (or "flushed" out) by the invading filtrate. With increased distance from the borehole, the amount of invaded filtrate decreases and pore space is filled with a larger proportion of original fluids (the transition zone). Beyond some distance from the borehole wall (i.e., the depth of invasion), mud filtrate does not exist and pores are filled entirely by original fluids (water and, hopefully, hydrocarbon). This region is known as the uninvaded zone; therefore, logging measurements taken at sufficiently deep depths of investigation are said to represent original conditions of the formation before invasion occurred.

Figure 4. Filtrate invasion creates a distribution of different fluid types in permeable formations.



The objective of acquiring resistivity measurements at multiple depths of investigation is not only to estimate uninvaded zone resistivity (Rt) using the deep measurement, but also to use the shallower measurements for investigating what happened during invasion. Shallow resistivities are more severely influenced by the presence of invaded mud filtrate. Deeper depths of investigation suffer less of an influence. Measures of resistivity at multiple depths of investigation can tell us something about how deeply a formation was invaded which, among other things, is a function of permeability. Furthermore, water saturation estimates calculated at different depths of investigation can tell us whether hydrocarbons were moved during invasion.

One thing we must be cautious of is how deeply a formation is invaded. The deeper the invasion, the greater the influence of mud filtrate on deep resistivity, and the less accurate our estimate of Rt. This is why we say that deep resistivity is only an approximation of Rt. We must consider that invaded mud filtrate is influencing the measurement to some degree. Corrections for the effects of this invaded filtrate can be applied to obtain a value of “true” formation resistivity. Once again, these corrections are rarely performed real-time, and are usually left to the discretion of the client.

Depth of investigation of shallow measurements must also be taken into consideration when judging how well they reflect conditions in the flushed zone. Some “shallow” measurements have depths of investigation that exceed the typical outer limits of the flushed zone, so it is possible (depending upon the depth of invasion) that a shallow measurement represents the transition zone rather than the flushed zone. Where invasion is very shallow, a shallow depth of investigation might actually represent the uninvaded zone! Understanding depths of investigation of the different measurements helps answer some of the questions revolving around invasion.

Invasion also plays a role in our porosity estimates. One of the reasons why wells are logged is to determine the type(s) of fluid present in the pore space. However, to estimate porosity from the measurements acquired by neutron, density and acoustic tools, we must know what type of fluid fills the pore space. To account for this unknown, we make an assumption: porosity estimates are calculated by assuming that a particular fluid saturates the pore space. Neutron, density and acoustic measurements have such shallow depths of investigation that they essentially represent the flushed zone. In a permeable formation, it is reasonable to expect that pore space of the flushed zone is filled mostly with invaded mud filtrate. Therefore, porosity estimates are calculated assuming any pore space is saturated by the same type of fluid that is present in the borehole (e.g., water in the case of water-based mud, and oil in the case of oil-based mud). If invasion is very shallow, however, porosity estimates might be in error because pore space of the flushed zone can be filled with a fluid type other than the one we assumed when calculating porosity.

Filtrate invasion, its dependency upon rock properties, the influence of the borehole and the effects of each on log responses can make data validation and evaluation of the reservoir difficult, to say the least. So, what is a "reservoir," and how do some of these influencing factors relate to one another? The more you understand about geology, the better off you are in answering some of these questions. Even without a good understanding of geology it is possible to make sense of and to validate log responses if you consider how and why rocks can be different. This means learning even more about the reservoir.

What Makes a Rock a Reservoir?

A reservoir is defined as any subsurface formation with enough porosity to store fluids and enough permeability to transmit them. This definition leaves a lot to be desired because it says nothing about how much porosity or how much permeability is required. One reason to log a well is to acquire estimates of these two properties and to make estimates about the types of fluids present, their volumes, and whether or not they are moveable. After all, we have very little interest in a reservoir unless it contains hydrocarbons, and then our interest is kept only if economic volumes of hydrocarbons can be moved.

Many people become frustrated in the early stages of learning about logs because they expect to see a unique or characteristic set of curve responses that says, "I am a reservoir!" They are oftentimes surprised and can be intimidated to find that such "classic" or "textbook" responses rarely exist. It is impractical to expect that a hydrocarbon-producing reservoir should have X-percent porosity and X-ohms resistivity, or that sandstone should always be a better reservoir than limestone.

Reservoirs can exhibit extreme variability in their petrophysical properties. Because it is a reservoir's unique set of petrophysical properties (e.g., lithology, porosity, saturations, permeability, etc.) that ultimately determines its curve responses, it should come as no surprise that interpreting these responses can sometimes be difficult. Lithology—as you are about to see—can have a very strong influence on reservoir properties. This is why determining lithology from logs is so important. If we have an idea about the rock type, then we can develop an idea for what to expect.

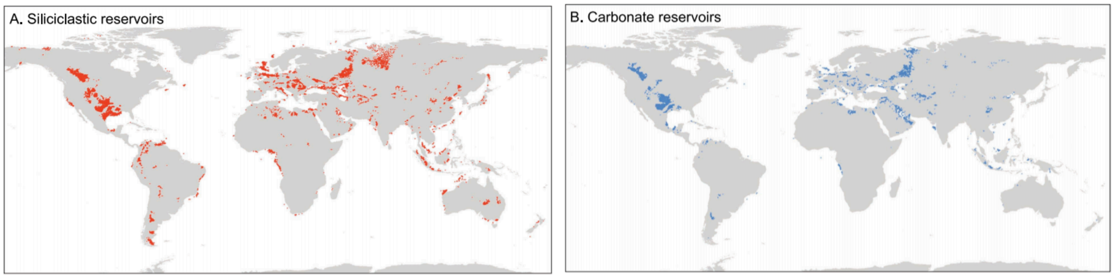
Most of the world's hydrocarbon reservoirs can be classified into one of two groups: siliciclastic or carbonate. Some reservoirs can also be classified as mixed siliciclastic-carbonate, depending upon their specific mineralogies. Figure 5 highlights some of the more common lithologies associated with these two groups of reservoirs.

Figure 5. Common lithologies associated with siliciclastic and carbonate reservoirs.

Siliciclastics	Carbonate
Dominated by Silicate minerals	**Dominated by carbonate minerals**
Conglomerate	Limestone
Sandstone	Dolomite
Siltstone and Shale	

It is common to think of sandstone as being an important reservoir (and rightfully so, given the porosity and permeability typically associated with sandstone). The importance of sand as a reservoir is supported by the fact that most of the world's hydrocarbon reservoirs are siliciclastic (Fig. 6). However, carbonates are responsible for a startling 70% of the world's oil and gas production. So, while siliciclastics are the most abundant reservoir type, carbonates are the most prolific producers.

Figure 6. Geographic distribution of petroleum reservoirs, sorted by lithology. (source)



What is it about these rocks that make them reservoirs? Most of the attractive features of these reservoirs, as well as their log responses, are somehow related to mineralogy and how the rocks are altered as a result of the physical and chemical changes affecting them since their deposition. Siliciclastic rocks (including conglomerate, sandstone, siltstone and shale) are largely derived from the erosion of pre-existing rocks and the subsequent deposition of sediments produced from them. These clastic rocks are characterized by a predominance of silicate minerals such as quartz, feldspar and micas. Silicate is a chemically resistant compound of silicon and oxygen (Si_XO_Y).

Carbonate rocks (including limestone and dolomite) form in a variety of ways, but their mineralogies are based on the carbonate ion (CO3). Common rock-forming carbonate minerals include:

Calcite CaCO3

Dolomite $CaMg(CO_3)_2$

One of the many factors distinguishing carbonate minerals from silicate minerals is their chemical reactivity. Because of the incredible strength of the silicon-oxygen bond, chemical and physical alteration of silicate minerals only becomes significant at the very high temperatures and pressures encountered during deep burial. Carbonates, being more chemically reactive, have the potential of being altered to a great degree by post-depositional physical and chemical processes. This suggests that both pressure and thermal exposure during burial play a large role in determining whether or not these rocks ultimately become reservoirs, and how much porosity and permeability they contain.

Porosity and permeability can be considered the two most important rock properties of interest to us because they are required for a formation to hold and to produce fluids, and because they exert such strong controls on the responses observed on logs. Comparisons of porosity and permeability in reservoirs and how their relationship differs in siliciclastic and carbonates have revealed some interesting trends:

• Porosity decreases with depth in both siliciclastic and carbonate reservoirs.

• Carbonate reservoirs generally have lower porosity at a given depth than siliciclastic reservoirs.

• Permeability in both siliciclastic and carbonate reservoirs is similar in rocks up to 20% porosity, but siliciclastic reservoirs often have higher permeability where porosity is greater than 20%.

• High porosity (> 20%) and high permeability (> 100md) is more common in siliciclastic reservoirs than in carbonate reservoirs.

• High permeability (> 100md) in low porosity rocks (< 8%) is much more common in carbonate reservoirs than in siliciclastic reservoirs.

What does all this mean? It means that we should not expect to see a unique or characteristic set of log responses indicating a hydrocarbon reservoir. Porosity and permeability both depend upon the physical characteristics of the rock and can be highly variable, even within the same type of rock. What we need to think about is how these properties change, and why.

Controls on Porosity

An important concept to keep in mind is that porosity can be created and porosity can be destroyed. Depending upon the depositional environments and energies associated with these environments, some amount of pore space can be created during deposition. After deposition, however, different physical and chemical processes (collectively referred to as diagenesis) can modify the amount of original porosity. The amount of porosity that we see preserved in reservoirs today is a product of both their depositional and diagenetic histories.

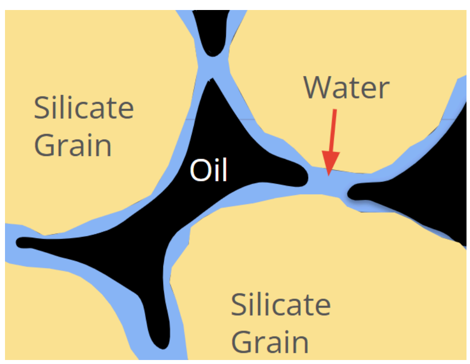
How much porosity is present in the reservoirs being logged is influenced by three factors:

1. The amount of original porosity.
2. Early diagenetic processes near the surface.
3. Diagenetic processes during deeper burial.

Original Porosity

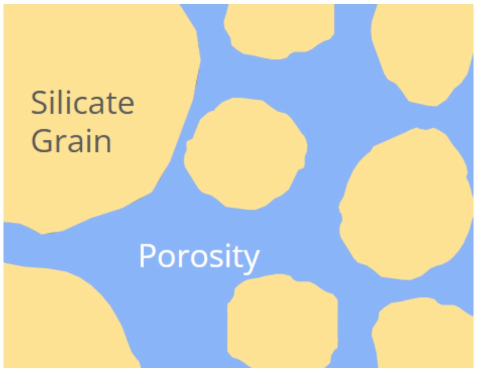
The creation of pore space in a siliciclastic rock is easy to visualize, if only because it is commonly how we envision a porous and permeable rock. Clastic sediments are deposited with intergranular pores forming between the silicate framework grains (Fig. 7). The amount of original porosity depends upon sediment characteristics such as grain shape and grain size distribution (or sorting). Well-sorted sediments have higher original porosities than poorly sorted ones.

Figure 7. Original intergranular porosity (fluid-filled) existing between framework silicate grains. This type of porosity is common in sandstones.

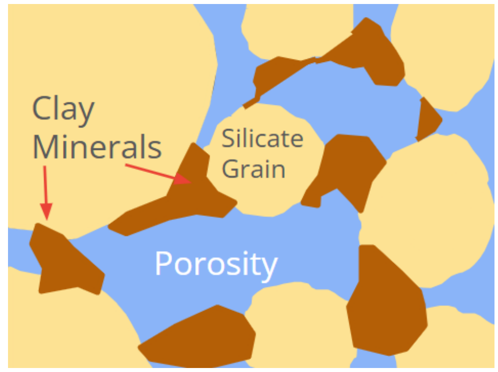


The amount of original porosity in siliciclastic rocks is also influenced to a great degree by the clay content of the sediments. With an increasing volume of clay, original porosity is reduced as those clay minerals begin filling the intergranular pore space (Fig. 8). Apart from causing a decrease in the original porosity of a formation, the volume of clay minerals in a rock (referred to as its 00000, sandstones that contain greater than 10-15% clay minerals by volume are referred to as “shaly sandstones.”) also poses problems in interpretation because of the effects of clay minerals on resistivity and porosity responses.

Figure 8. Reduction of original porosity in sandstone caused by an increase in clay volume.



Clean sand and sediments

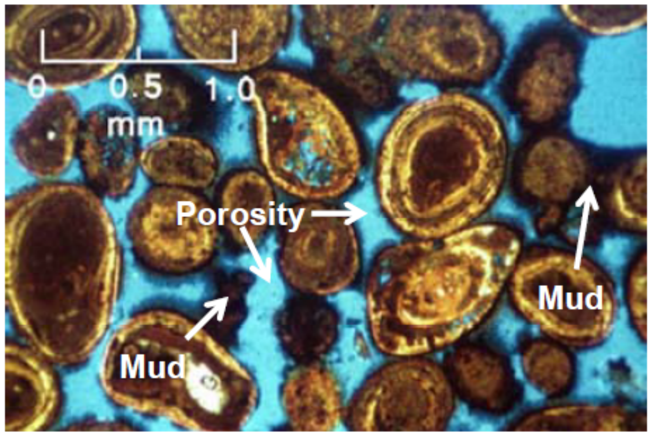


Shaly Sand sediments

Sorting and clay content in siliciclastic rocks have a direct relationship to depositional energy. In high energy environments (e.g., shallow marine waters or river channels), strong water currents wash away fine-grained clay minerals to result in better sediment sorting. In lower energy environments, these currents are not as strong, and sorting becomes much poorer as clay content increases. Clean siliciclastic rocks (those containing insignificant amounts of clay minerals) deposited in high energy environments usually have large amounts of original porosity. At question, then, is whether or not this porosity will survive long enough for the rock to become a reservoir.

The original pore space in a carbonate rock can be more difficult to visualize because carbonates are deposited over such a wide range of depositional environments and energies. Some contain intergranular pore space much like siliciclastic rocks, while others might contain pore space within carbonate grains themselves. Perhaps the strongest control on the amount of original porosity in a carbonate rock is the volume of carbonate mud. Much like the problem of shaliness (i.e., increased clay volume) in siliciclastics, increasing volumes of carbonate mud decreases the sorting of sediments and causes a reduction in their original porosity (Fig. 9).

Figure 9. Thin-section photograph of a carbonate rock with low mud content. Original porosity is reduced as mud content increases.



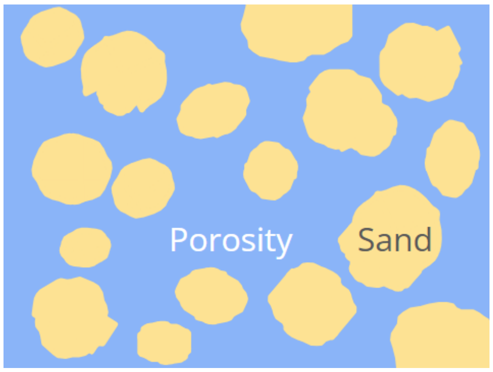
Mud content in carbonates is also directly related to depositional energy. In high energy shallow water marine environments, strong water currents wash away any mud-sized carbonate sediments to produce well sorted and high porosity deposits. As the water depth increases, these currents are not as strong and carbonate mud begins infilling pore space. High energy depositional environments tend to result in carbonates with the greatest amounts of original porosity. Once again, the question is whether this original porosity can survive what happens next to the rock.

Early Diagenetic Changes

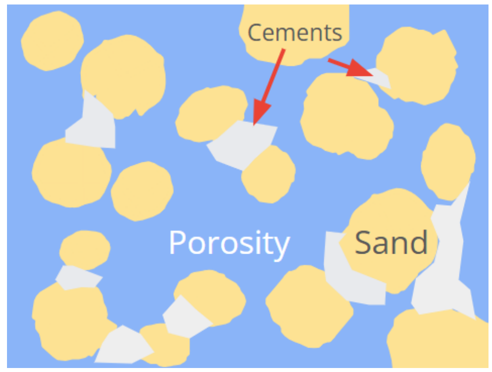
Following deposition of siliciclastic and carbonate sediments, there begins a very long period of time during which these deposits can become deeply buried and subjected to the effects of much higher temperatures and pressure. Even before temperature and pressure are high enough to cause chemical or physical alteration of the rocks, sediments are often exposed to a number of early diagenetic processes near the surface at shallow depths of burial. These early processes usually involve the infiltration of fluids from the surface down into the unconsolidated sediments.

Silicate minerals, because of their chemical stability, are usually not altered to any great extent by the low temperatures and pressures of shallow burial. However, it is at this stage of early burial that cementing minerals begin to precipitate within the original porosity of siliciclastic rocks (Fig. 10). The mineralogies of these cements depend upon the chemistries of fluids percolating through the pore space. With increasing amounts of cementing minerals, the original porosity of the rock is reduced.

Figure 10. Precipitation of cementing minerals within the intergranular pore space of siliciclastic rocks at shallow depths of burial begins a reduction in original porosity.



Unconsolidated Sand



Moderately Cemented Sandstone

What happens to carbonate deposits at shallow depths of burial can be complicated because of their chemical reactivity. The chemistry of pore waters at shallow depths might be such that it causes the dissolution of carbonate, thus increasing original porosity. However, carbonates are also prone to the same cementation processes that affect siliciclastics. The same carbonate mineral that was dissolved might later be re-precipitated as porosity-reducing cements. Dolomitization occurring at near-surface conditions has ambiguous effects on original porosity. Some carbonate environments are characterized by very high rates of evaporation and hyper-saline waters. In these cases, the carbonate rocks are subject to porosity reduction caused by the emplacement of cementing minerals like gypsum, anhydrite and halite.

Certainly a rock’s mineralogy determines the extent to which these shallow diagenetic processes influence original porosity, but both siliciclastics and carbonates can suffer from porosity reduction during early burial. Even so, both types of reservoirs exhibit a wide range of porosities at shallow to intermediate depths. This trend likely reflects the diversity of depositional environments leading to the creation of original porosity, and the wide variety of early diagenetic processes that can potentially modify (increase or decrease) that porosity.

Burial Diagenetic Changes

Siliciclastic and carbonate reservoirs both exhibit trends of decreasing porosity with depth. This suggests that the temperatures and pressures associated with burial become important controls on porosity, and that diagenetic processes continue to reduce the amount of pore space. Temperature is thought to be the primary control, but it works together with the much higher pressures resulting from a thicker overburden.

Compaction caused by thicker overburden can result in some porosity loss, but the effects of compaction are further compounded by the continued precipitation of cementing minerals. Also, authigenic clay minerals might precipitate within intergranular pores, depending upon pore fluid chemistry. At high enough pressures, quartz itself can be dissolved and might re-precipitate as cement. In carbonates, dolomitization and dissolution during burial can continue to modify existing pore space, as can the precipitation of pore-filling cements.

The observation that, for a given depth, carbonates have lower porosities than siliciclastics can again be explained by mineralogy differences. Though slightly more unstable at the higher temperatures and pressures associated with deeper burial, siliciclastic rocks remain quite resistant to chemical modifications of porosity. Carbonates, however, continue to suffer more dramatic porosity reduction because of their chemical reactivity. As a result, siliciclastics tend to have higher porosities at depth. Carbonates still remain viable reservoirs, even though their porosities are not as high as siliciclastics.

Controls on Permeability

There is one absolute when dealing with porous media: a rock with no porosity cannot be permeable. Apart from this, anything goes! You might encounter a high porosity reservoir with high permeability, or that same reservoir might have no permeability if the pores are not interconnected. It is even possible to find a low porosity rock with excellent permeability resulting from natural fractures. The point is, it is very difficult to find a relationship between porosity and permeability that works in all cases.

Over a porosity range of 5-20%, both siliciclastic and carbonate reservoirs have similar permeabilities. Outside the limits of this range, however, is where significant differences exist. Combinations of high porosity (> 20%) and high permeability (> 100md) are much more common in siliciclastic reservoirs, presumably because siliciclastic rocks are dominated by intergranular pores. Intergranular pores, provided they are unobstructed by clay minerals and cements, lead to reservoirs with high permeability. Furthermore, because of silicate minerals' low chemical reactivities, the diagenetic processes working to reduce porosity (and also permeability) likely do not have a very dramatic effect. In summary, porosity and permeability tend to be better preserved in siliciclastics than in carbonates.

But what about low porosity reservoirs that have good permeability? Even though they contain smaller volumes of hydrocarbons, it might still be possible to produce this hydrocarbon at economic rates if permeability is high enough. Most of these reservoirs tend to be carbonates, not siliciclastics. Natural fractures are much more common in carbonates than in any other type of rock. Therefore, provided that sufficient porosity exists to contain economic volumes of hydrocarbon, and provided that natural fracturing of the rock has increased permeability by connecting fluid-filled pore space, low porosity carbonates can make for excellent reservoirs.

Never expect to see a unique set of curve responses on logs that is indicative of a hydrocarbon reservoir. Instead, expect to see quite a diversity of responses—and thick about how porosity and permeability (and their relationship to lithology) might influence these responses.

Rock Properties, the Borehole, Invasion, the Reservoir and You

Conventional logs (e.g., triple-combo and quad-combo) provide all of the necessary information for clients to perform a basic evaluation of their reservoir's productive potential. Based on the information acquired, the client will determine such things as lithology and water saturation, and look for qualitative indicators of the presence of permeability. The ultimate goal of this preliminary evaluation is to decide if drilling the well was a success—to determine whether or not the reservoir contains economic quantities of hydrocarbons and will be able to produce them.

In many cases, the decision of whether to complete or abandon a well is made at the wellsite, and using nothing more than conventional porosity and resistivity logs. While there is a certain risk in making this decision without the additional information provided by more advanced services, the client must also be concerned with cost. More information requires a bigger investment. To some, their experience and success with making decisions based on knowledge of formation properties obtained from triple- or quad-combo logs justifies not making that additional investment. Therefore, the standard porosity and resistivity services are the heart of the logging industry and critical to clients. Data of the highest quality possible is an absolute must if the client is to continue using them successfully for what they are intended: evaluating the reservoir. Ensuring this quality is the responsibility of the field professional of the service company, and—just like interpreting logs—doing so requires a knowledge of formation properties, borehole properties, invasion, and how each influences the logging measurements.

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