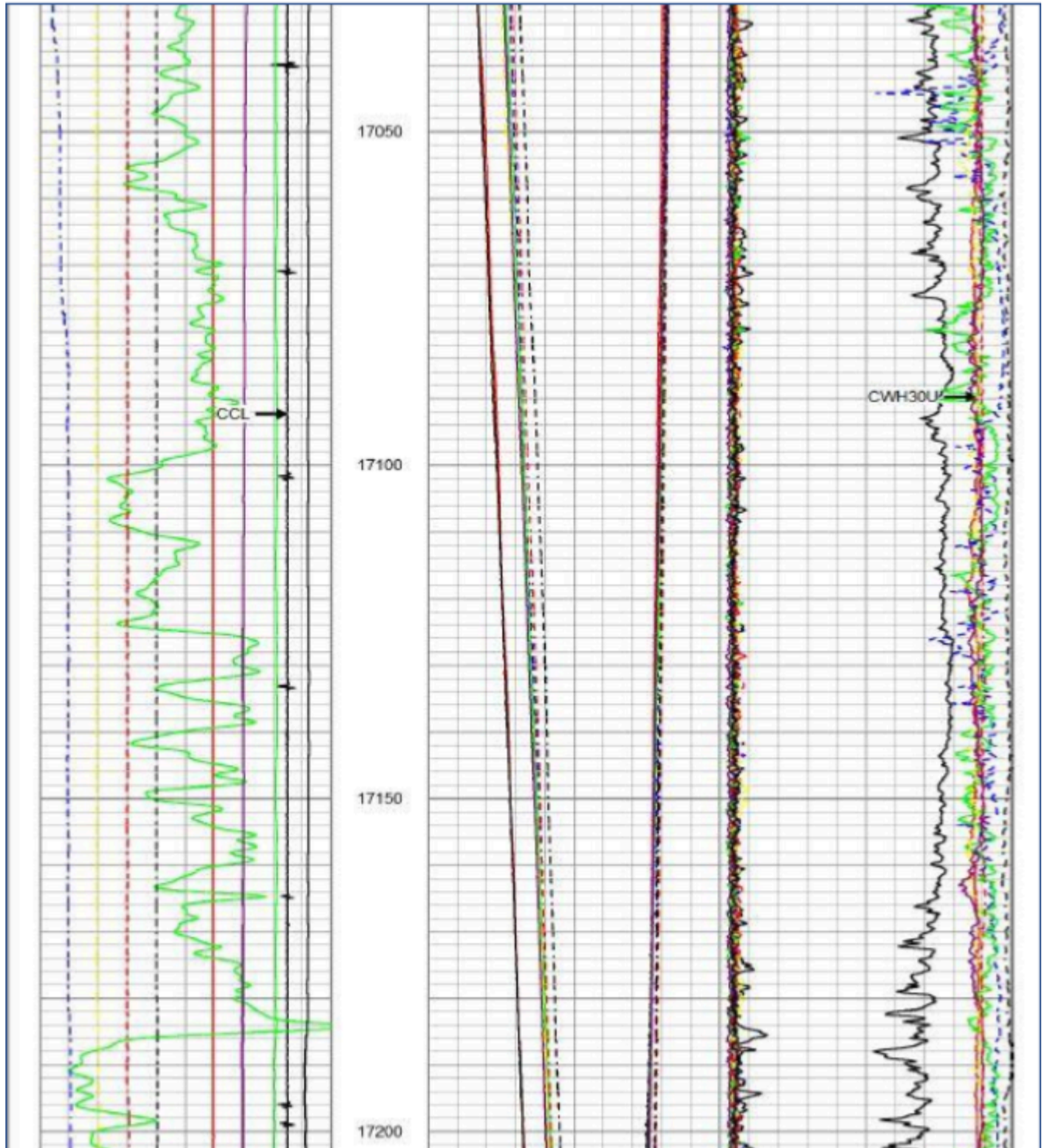


Chapter 3 - Resistivity Tools part I



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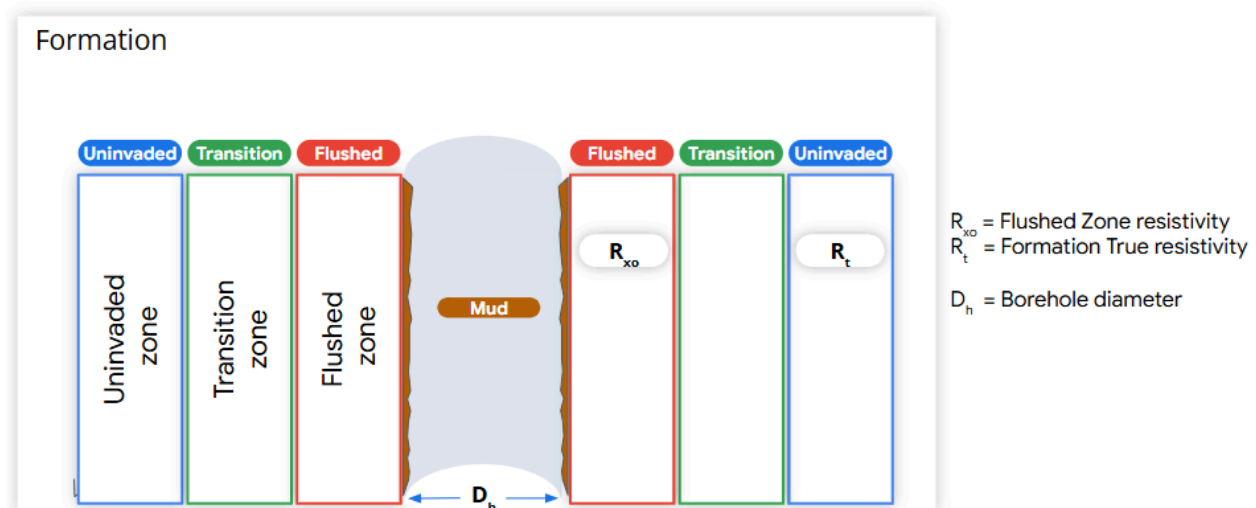
Chapter 3 - Induction Tools

Induction Tools provide measures of formation resistivity at multiple distances from the borehole. Although the tool responds to formation conductivity (in units of mmho/m), results are presented in units of resistivity ($\Omega\text{-m}$) by industry standard. Resistivity is the reciprocal of conductivity.

$$\text{Resistivity} = \frac{1,000}{\text{Conductivity}}$$

The primary objective of an induction tool is to determine a value for true resistivity (R_t) of a formation; that is, resistivity of the uninvaded zone (Fig. 1). This formation property can be estimated from the induction tools measurement taken farthest from the borehole, but requires corrections for the influence of the borehole, shoulder beds and invaded fluids to determine a more precise value.

Figure 1. Determining true formation resistivity (R_t) is the primary objective of logging an induction tool.



Applications

With knowledge of true resistivity (R_t) and formation porosity (Φ), the fraction of pore space occupied by water (or water saturation) can be calculated using the Archie equation, commonly expressed as the following:

$$S_w^n = \frac{a}{\Phi^m} \times \frac{R_w}{R_t}$$

Where: S_w = water saturation of the uninvaded zone
 n = saturation exponent
 a = tortuosity factor
 Φ = porosity
 m = cementation exponent
 R_w = formation water resistivity
 R_t = true resistivity of the uninvaded zone

If water saturation is known, the hydrocarbon saturation of the reservoir can be determined using the following equation:

$$S_{hc} = 1.0 - S_w$$

Where: S_w = water saturation of the uninvaded zone

S_h = hydrocarbon saturation of the uninvaded zone

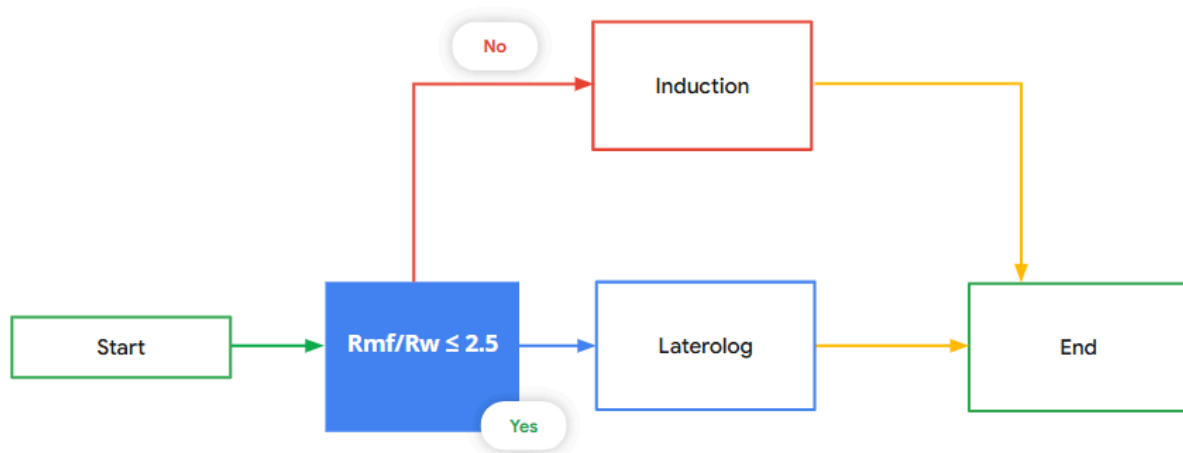
The multiple depths of investigation provided by an induction tool allow log analysts to also determine such things as the depth of fluid invasion, the presence of moveable hydrocarbons, and to qualitatively estimate permeability of a formation.

Logging Conditions

Induction tools are designed to obtain the best results in non-conductive and low-conductivity borehole conditions (Fig. 2). These fluids include the following:

- Air-drilled boreholes
- Oil-based mud
- Fresh water-based mud

Figure 2. Preferred operating environments for resistivity tools.



In saltwater-based drilling fluids, the borehole effect would be too large for an induction tool to provide an accurate measure of formation resistivity. The Laterolog Tool provides accurate results in those conditions where there is low contrast between the salinity of mud filtrate and the salinity of formation water.

Physics of the Measurement

The measurement principle of the induction tool relates to the theory of electromagnetic induction and can be explained by Ampere's law and Faraday's law. Ampere's law predicts that an alternating current supplied to a coil of wire will create an alternating magnetic field in the surrounding medium (Fig. 3). Faraday's law predicts that the time rate of change (or flux) of this magnetic field will induce an electromagnetic force (emf) in the surrounding medium. The presence of this emf will cause an eddy—or ground loop—current to flow through the medium (Fig. 4).

Figure 3. Alternating current in a coil of wire induces current flow in a formation (Faraday's law).

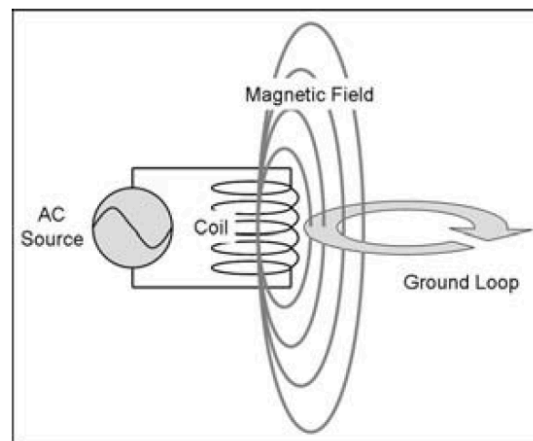
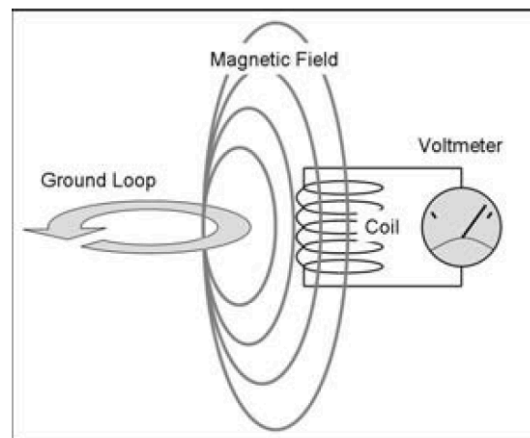


Figure 4. A magnetic field intersecting a coil of wire induces a voltage (Ampere's law).

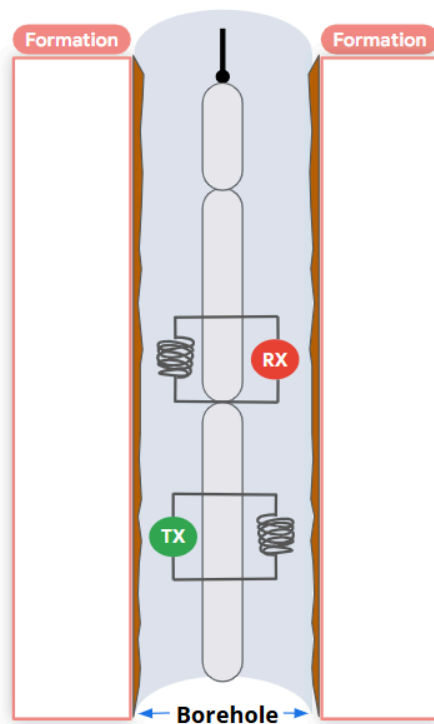


By combining Ampere's law and Faraday's law, an alternating current in a coil of wire creates a magnetic field that induces current flow in the surrounding formation. Ampere's law predicts that a ground loop current flowing through a medium will create its own magnetic field. Then, according to Faraday's law, if the flux lines of this magnetic field intersect the wire of a coil, a magnetic field will generate an alternating voltage in that coil of wire. Simply stated, the ground loop flowing in the formation will create a magnetic field that induces an electromagnetic force (emf) in the coil of wire.

The induction tool makes use of these laws of physics to measure resistivity of the environment surrounding the tool. A transmitter coil establishes the electromotive force in the formation that induces a ground loop. The magnitude of the current flow in this ground loop is inversely proportional to formation resistivity.

The ground loop itself produces another magnetic field that intersects a receiver coil and induces a voltage. This voltage is proportional to the strength of the magnetic field that induced it, and is thereby inversely proportional to formation resistivity. As explained, the concept of electromagnetic induction might seem straightforward, but the induction tool is a complex tool that employs multiple transmitter coils and receiver coils. Therefore, a closer look at the magnetic fields and current flows induced in the formation and their relationships to the measured signal is necessary. A good place to start is to consider a simple induction tool with a single transmitter coil and a single receiver coil that is placed in a borehole filled with air (Fig. 5).

Figure 5. Simplified induction tool consisting of a single transmitter and a single receiver.

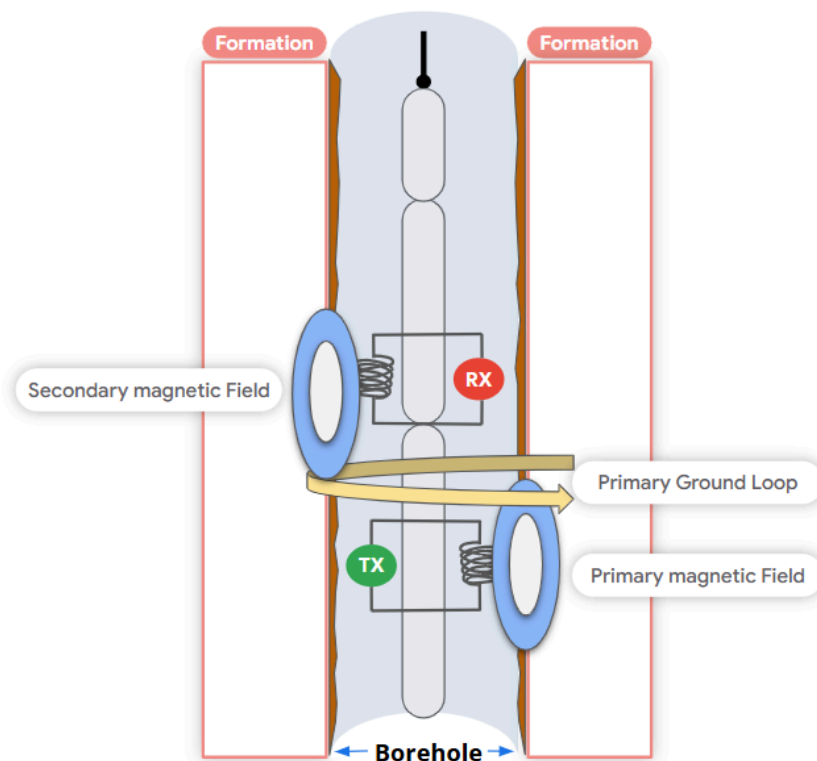


Alternating current supplied by a power source to the transmitter coil establishes an electromotive force in the formation. This emf induces a primary ground loop in the formation and current flows coaxially around the long axis of

the tool. The primary ground loop, in turn, generates its own secondary magnetic field that intersects the receiver coil and induces an alternating voltage (Fig. 6).

The voltage measured in the receiver coil is proportional to the strength of the primary ground loop, the magnitude of which is inversely proportional to formation resistivity.

Figure 6. The primary magnetic field induces the primary ground loop which, in turn, creates a secondary magnetic field that intersects the receiver coil.

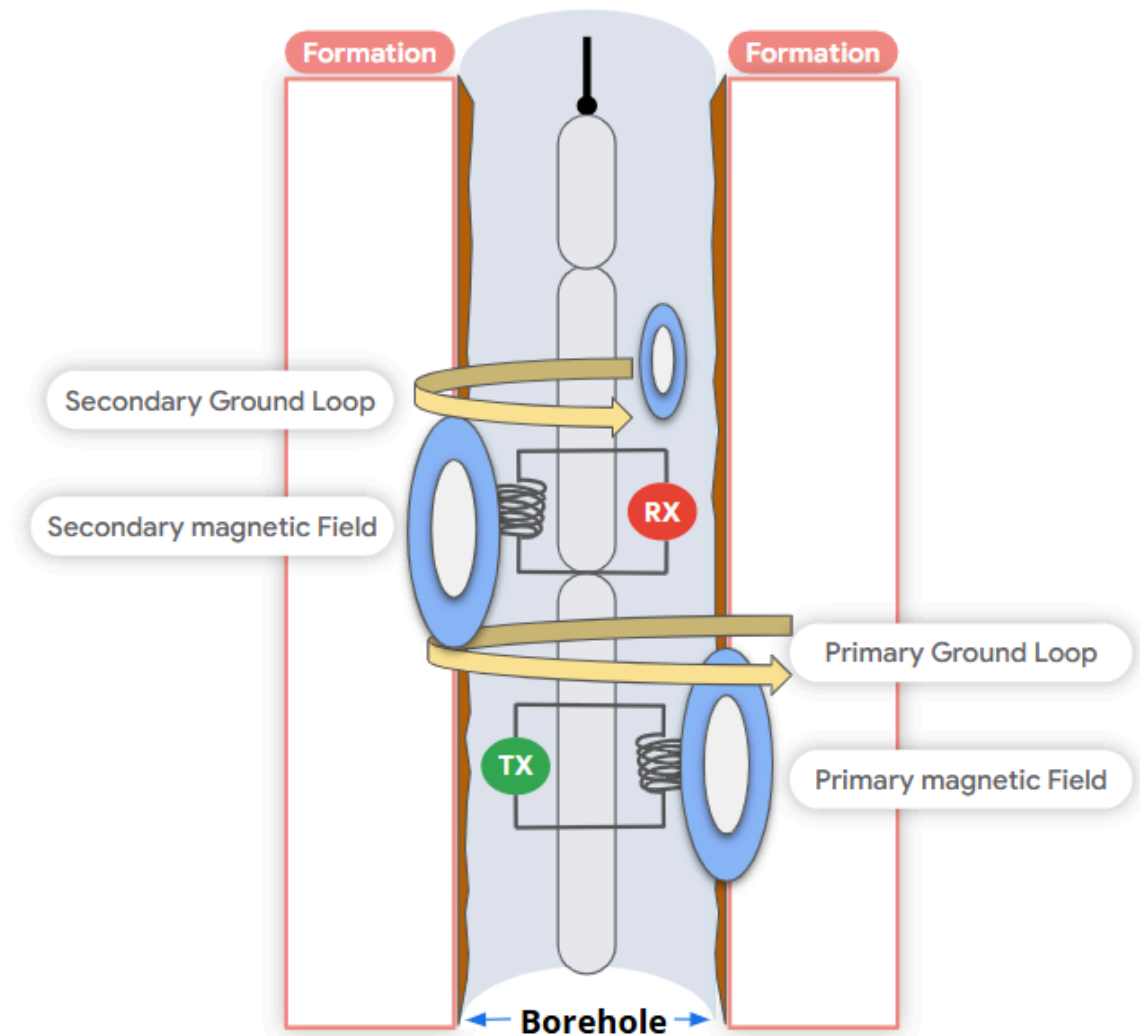


Unfortunately, the primary magnetic field created by the transmitter also intersects the receiver coil and induces a voltage of its own. This phenomenon is referred to as direct mutual inductance, or mutual coupling of the transmitter coil to the receiver coil. The mutual coupling signal generated in the receiver coil can be thousands of times greater than the signal generated by the primary ground loop's magnetic field. Therefore, the mutual coupling signal must be eliminated so that it does not result in incorrect measurements of formation resistivity.

In very low resistivity formations the magnitude of the primary ground loop current can become quite large. If this is the case, then the magnetic field produced by the primary ground loop will generate an infinite number of secondary ground

loops in the formation (Fig. 7). These secondary ground loops are also proportional to formation resistivity.

Figure 7. In very low resistivity formations, secondary ground loops are generated by the secondary magnetic field.



The secondary ground loops that exist in very low resistivity formations produce yet another magnetic field that also intersects the receiver coil and induces a voltage. As a result, in very low resistivity formations, the voltage signal induced in the receiver coil is a function of the primary ground loop's magnetic field and the magnetic field produced by the secondary ground loops.

To summarize, the receiver coil measures a signal which is a composite of three separate voltages, including:

1. A voltage induced by the primary ground loop's magnetic field. This is the component of greatest interest, and is inversely proportional to formation resistivity. This voltage is known as the R-signal.
2. A voltage induced by mutual coupling of the transmitter coil to the receiver coil. This undesirable voltage component—known as the mutual signal—must somehow be eliminated.
3. A voltage induced by magnetic fields related to secondary ground loops in very low resistivity formations. This component is also of interest because it allows for the correction of a phenomenon called skin effect. This voltage is known as the X-signal.

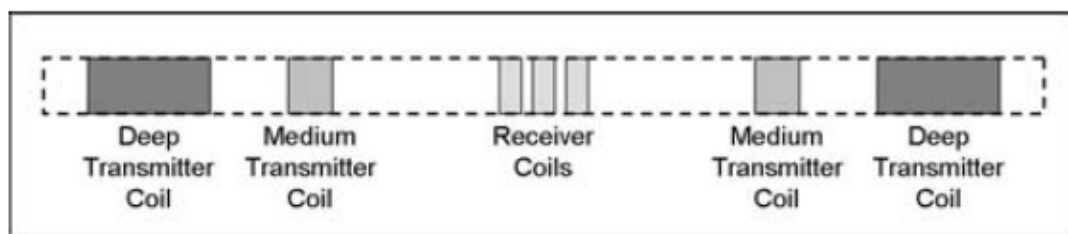
The voltage measured in the receiver coil can, therefore, be expressed as:

$$VRX = \text{mutual signal} + \text{R-signal} + \text{X-signal}$$

Mutual Signal

For a simple two-coil induction tool the largest receiver voltage component is the mutual signal. This signal is an artifact of the tool and must be eliminated in order to obtain accurate measures of formation resistivity. The primary method of minimizing the undesirable mutual signal is to employ multiple transmitter coils and/or multiple receiver coils. Modern induction tools are mutually balanced, meaning they are designed with multiple coils in series with opposed windings that serve to significantly reduce mutual coupling (Fig. 8).

Figure 8. The multi-coil design of an induction tool significantly reduces mutual coupling.



Even with a mutually balanced multi-coil tool there still remains some small amount of residual coupling between the transmitter coil and the receiver coil. The small and constant voltage signal created by this residual coupling is known as sonde error.

Sonde error is accounted for by proper shop calibration of the induction tool. In a non-conductive calibration environment, the measured tool response is only a function of the mutual signal. By characterizing this response in a zero-conductivity calibration environment, the effects of sonde error can be subtracted from the measurement.

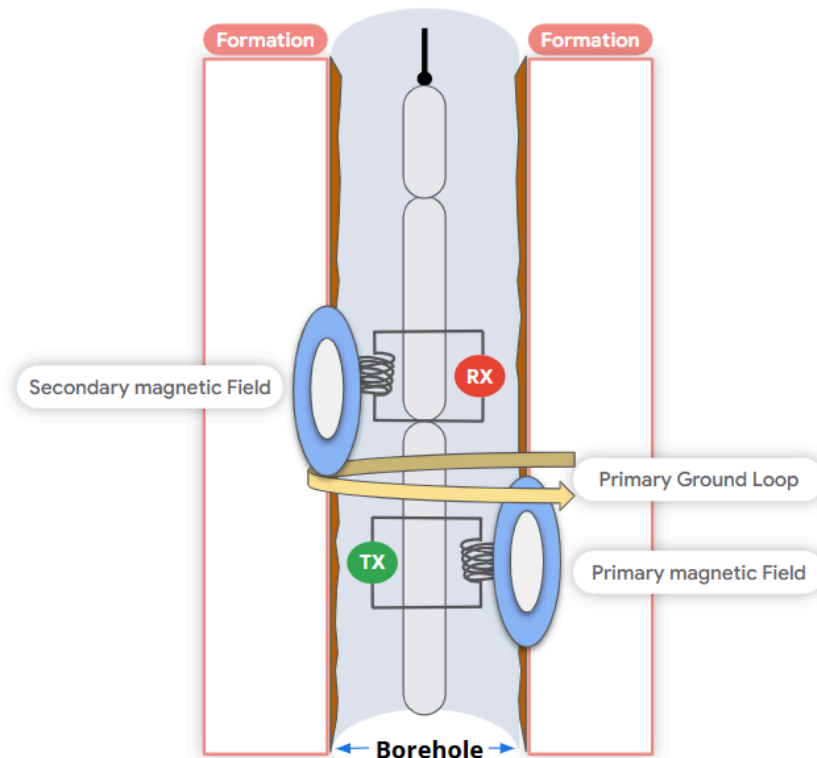
After subtracting sonde error, the measured voltage can be expressed as a function of formation dependent components:

$$VRX = R\text{-signal} + X\text{-signal}$$

R-Signal

The voltage induced by the primary ground loop's magnetic field is the main signal of interest and is known as the R-signal (Fig. 9). The R-signal is inversely proportional to formation resistivity because it is directly related to the magnitude of the ground loop current induced in the formation.

Figure 9. The R-signal is related to the magnitude of the primary ground loop.

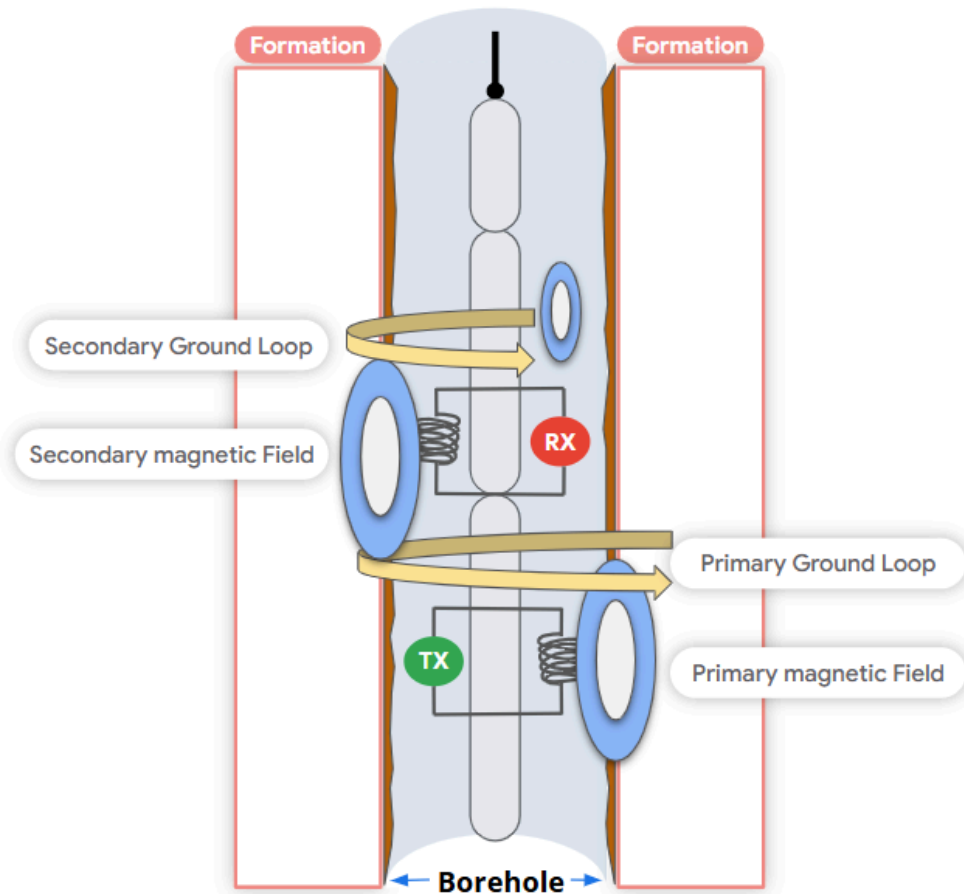


The R-signal has a 180-degree phase relationship with the transmitter current, and is said to be in-phase with the transmitter current.

X-Signal

In very low resistivity formations the magnitude of the primary ground loop current can be large enough that secondary ground loops are created. These secondary ground loops produce their own magnetic field and induce another voltage in the receiver known as the X-signal (Fig. 10). The Xsignal is also inversely proportional to formation resistivity, but it is only significant in very low resistivity formations where the primary ground loop current is large enough to create the secondary ground loops.

Figure 10. The X-signal is related to the magnitude of secondary ground loops in very low resistivity formations.



X-Signal in High Resistivity Formations

In high resistivity formations the primary ground loop is small. Consequently, its magnetic field does not generate significant secondary ground loops in the formation. As a result, the R-signal related to the primary ground loop is the predominant component of the receiver voltage. The Xsignal related to any ground loops is insignificant.

X-Signal in Low Resistivity Formations

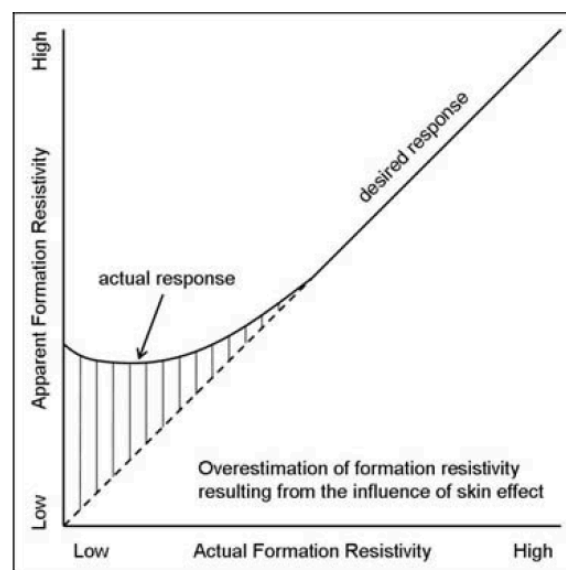
As formation resistivity decreases, the magnitude of the primary ground loop current increases and secondary ground loops become more significant. The magnetic field associated with these secondary ground loops induces the X-signal in the receiver coil. Because of the presence of secondary ground loops in very low resistivity ($< 3 \Omega\text{-m}$) formations, the R-signal is no longer inversely proportional to

formation resistivity. This phenomenon of the R_{signal} no longer being inversely proportional to formation resistivity is known as skin effect.

What happens in very low resistivity formations can be quite confusing. Induced ground loops in the formation cannot be considered independent systems. Each will feel the opposing force of its own magnetic field (self-induction). Each ground loop will also feel the opposing forces of those magnetic fields associated with all other ground loops (mutual induction).

Conservation of energy is the simplest analogy for explaining how skin effect influences induction measurements in very low resistivity formations. The only way in which secondary ground loops are generated is if the emf caused by the primary ground loops yields some of its energy. By yielding this energy, the magnetic field generated by the primary ground loop induces a smaller R_{signal} in the receiver coil. This smaller R_{signal} results in the overestimation of formation resistivity in these very low resistivity formations.

Skin effect is the single largest influence on induction tool measurements in very low resistivity formations. In such conditions, skin effect manifests itself as a measure of apparent resistivity that is higher than the actual resistivity of the formation (Fig. 11). Figure 11. The X_{signal} is related to the magnitude of secondary ground loops in very low resistivity formations.



A major concern in the development of induction tools since their introduction in 1949 has been how to correct for skin effect in very low resistivity formations. The HRID is unique among induction tools in that it dynamically corrects for skin effect through its measurement of the X-signal.

Because the X-signal and R-signal have different phase relationships with transmitter current, they can be distinguished from one another. Furthermore, the X-signal is only significant in very low resistivity formations where skin effect is a problem. It is possible to use the measurement of the X-signal to characterize the influence of skin effect on resistivity measurements and correct for it in very low resistivity formations.

Summary of the Receiver Signal

To summarize, a voltage is induced in the receiver coil which is a composite of desirable and undesirable signals:

1. The mutual signal can be largely eliminated through the use of multi-coil tools. Any residual mutual signal (or sonde error) can be characterized during calibration in a zero-conductivity fluence of environment and be subtracted from the measurement during logging.
2. Phase relationships of the R-signal and the X-signal allow them to be identified and measured separately. In higher resistivity formations the R-signal is free from the in skin effect and is inversely proportional to formation resistivity. In very low resistivity formations ($< 3 \Omega\text{-m}$) the R-signal is influenced by skin effect and the X-signal is used to correct for the influence of skin effect.

Resolution of the Measurement

Multi-coil induction tools (two-coil induction tool (Fig. 5) that was used Fig. 12) have tremendous advantages over the simple to explain induction principles. Most obvious should be the minimization of the mutual coupling signal. Additional advantages include the ability to make resistivity measurements at multiple and greater distances from the borehole (multiple depths of investigation) while maintaining a fine vertical resolution of the formation measured. Factors

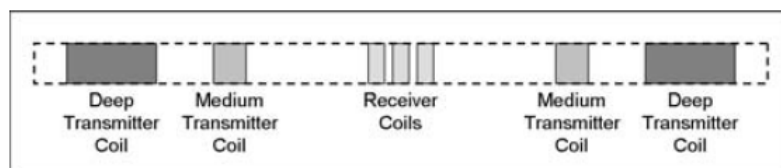
controlling the depth of investigation (DOI) and vertical re-resolution of a multi-coil induction include the transmitter-to-receiver spacing.

To achieve the desired results—a deep DOI and a fine vertical resolution—an optimized coil arrangement is necessary. With any induction tool, as the distance between the transmitter coil and the receiver coil is increased, the DOI increases but the vertical resolution worsens, and vice versa. The “trade-offs” between DOI ¹ and vertical resolution ² must be balanced.

A balance is achieved in inductions tools by using a single 3-coil receiver set and two pairs of transmitter coils. The single 3-coil receiver set is designed to maintain fine vertical resolution, regardless of the transmitter-to-receiver spacing. The receiver coil design is proprietary of each tool manufacturer and provides 2-ft matched vertical resolutions for both the deep and medium DOI of the induction tool.

Two depths of investigation are achieved by using two transmitter coil pairs in combination with the receiver coil set (Fig. 12). The symmetrical positioning of the transmitter coil pairs ensures a vertically symmetrical response from the tool

Figure 12. An induction coil array.



The long Tx-Rx spacing of the deep coil array provides a 91-inch DOI for the deep measurement. The deep measurement of the induction tool is well respected in the industry for its deep DOI and fine vertical resolution, and provides a measurement resolution better than some of the newer array induction tools of the competition. The shorter spacing of the medium coil array provides a 39-inch DOI for the medium measurement.

The deep (91-inch) resistivity result of the induction tool is commonly assumed to represent the true resistivity (R_t) of the uninvaded zone. It should be noted that this result can be influenced by the resistivities of the borehole, shoulder

beds, and invaded mud filtrate. Therefore, a true value of R_t can only be obtained by correcting the deep measurement for these environmental influences.

¹ Depth of investigation is defined as the distance from the tool beyond which 50% of the measured signal originates. For example, consider a tool with a 91-inch DOI. Half of the tool's measured signal originates from the volume beyond a 91-inch radius of the tool, while the remaining half originates from the volume within a 91-inch radius of the tool.

² Vertical resolution is defined as the minimum bed thickness that can be observed on a tool's response. For instance, a tool with a 2-ft VR is capable of responding to a formation that is 2-ft thick; however, this does not necessarily mean the tool is capable of an accurate measurement in such a thin formation. In very thin formations, a large percentage of the tool's response depends on the properties of adjacent formations.

Formation Water Resistivity

The salinity of water existing in the pores of a rock has a direct relationship to that rock's measured resistivity. It can be safely assumed that all subsurface formations contain at least some volume of "original" water that was either trapped within the sediments at the time of their deposition or which infiltrated the permeable rock sometime later. Depending upon its source, this water can be salty or fresh. Salinity generally increases with depth; however, formation water salinity can be quite variable in different geologic and geographic settings.

Formation water resistivity (R_w) is completely independent of the presence of any non-conductive hydrocarbon or matrix. The measured resistivity of a rock is directly proportional to the resistivity of the water contained in its pore space. The higher the salinity, the lower the R_w and, therefore, the lower the rock's measured resistivity. Most subsurface formation water is moderately saline, but there are certainly exceptions to this generality.

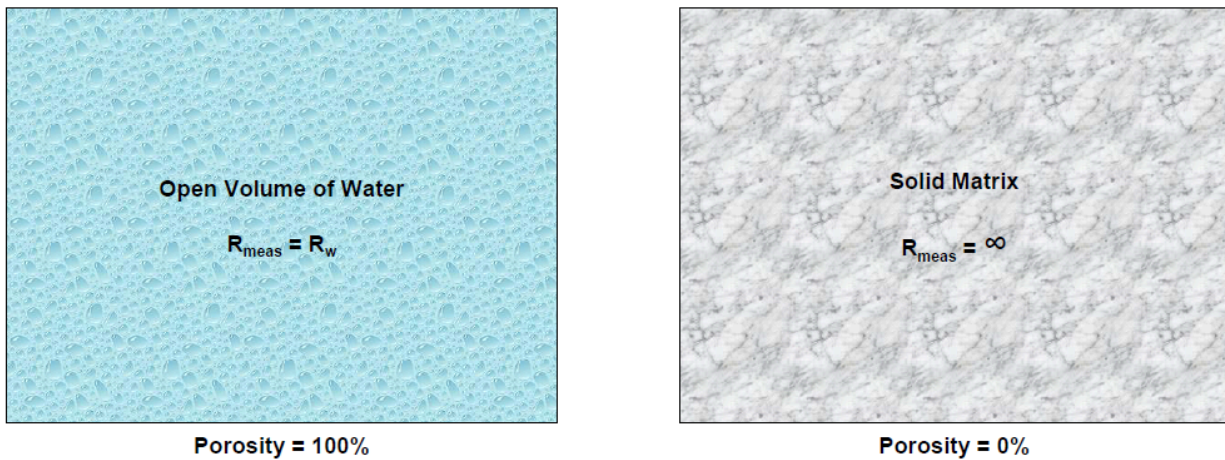
The relationship between formation water resistivity (R_w) and measured resistivity of a formation is expressed as follows:

$$R_{\text{meas}} \propto R_w$$

Porosity

Porosity is another factor that determines a rock's resistivity. If we consider two extreme cases (Fig. 13), then it can be shown that resistivity *is* inversely proportional to the amount of porosity. For an open volume of water ($\Phi = 100\%$), measured resistivity equals formation water resistivity (R_w). On the other hand, measured resistivity of a volume of solid matrix ($\Phi = 0\%$) is infinite because current cannot flow through a non-conductive matrix. Although resistivity is inversely proportional to the amount of porosity, the primary requirement for current to flow through a rock is the presence of effective pore space. This means that the path of current flow is controlled by the *complexity* of the interconnected pore network, not just the *amount* of porosity.

Figure 13. For an open volume of water ($\Phi = 100\%$), the measured resistivity equals formation water resistivity (R_w). For a volume of solid matrix ($\Phi = 0\%$), the measured resistivity is infinite.



The relationship between measured resistivity of a formation and the amount of porosity it contains is expressed as follows:

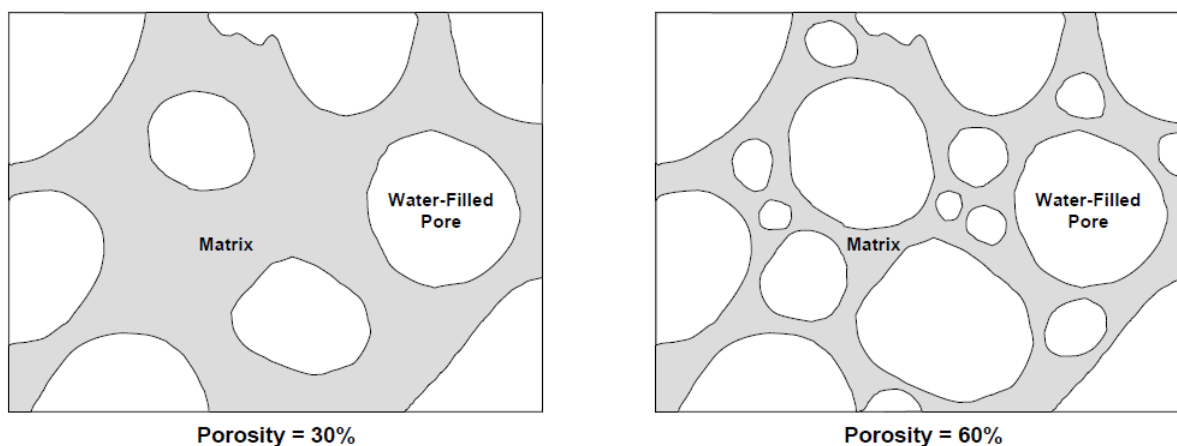
$$R_{\text{meas}} \propto \frac{1}{\Phi}$$

Pore Tortuosity

The amount of pore space in a rock, however, is not the only factor to warrant consideration. A primary requirement for current flow through a rock is the presence of interconnected (i.e., effective) pore space. This means a rock's resistivity is also related to the distribution of effective porosity and the length of current flow through that interconnected pore space.

The presence of isolated pore space causes problems when using resistivity measurements for evaluating saturations. This problem is demonstrated by a model formation resembling Swiss cheese (Fig. 14). Electrical current cannot flow through a rock with perfectly isolated pores. Regardless of how much water-filled pore space exists, the resistivity of such a rock is infinite. If unaware of the presence of isolated pores, then the higher resistivities that are observed can easily be mistaken as the result of a larger volume of hydrocarbon. Fortunately, rocks with perfectly isolated pores are rare, but even those with only a small fraction of isolated porosity are a concern when estimating saturations.

Figure 14. "Swiss cheese" rocks with water-filled and perfectly isolated pores. A change in porosity does not cause a change in resistivity because there is no interconnected water-filled path available to current flow. Resistivity is infinite in both cases.

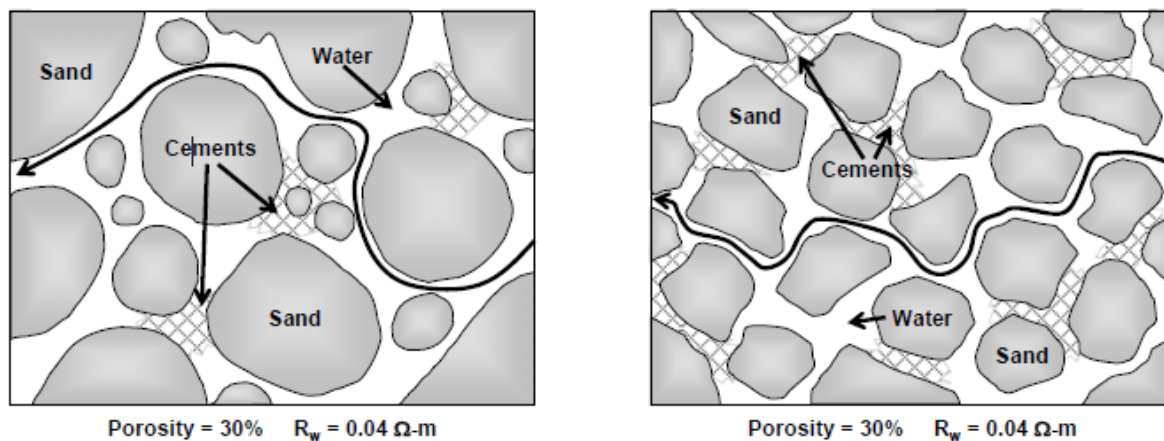


Resistivity is inversely proportional to porosity and directly proportional to the resistivity of any water in that pore space. Interconnected pore space is a primary requirement for current to flow. Common sense, then, says two water-saturated rocks with the same porosities (all effective) and waters of equal salinity should

have equal resistivities. Given the influence of matrix characteristics on the path followed by electrical current, this is not the case.

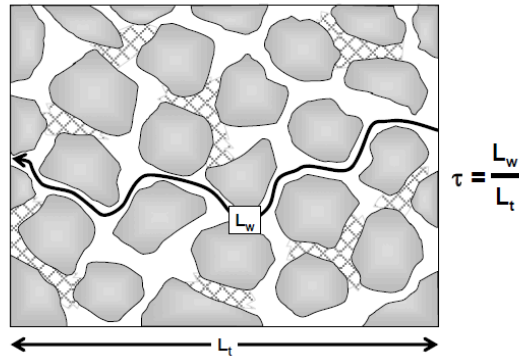
A complication to the simple relationship between porosity and resistivity arises when considering different rocks (Fig. 15). The length of the path followed by electrical current is strongly dependent upon matrix characteristics such as grain size, grain shape, sorting, and the presence of cementing minerals. Because no two rocks are ever identical in terms of these characteristics, two water-saturated rocks with the same porosities and same water salinities will never have absolutely equal resistivities. The distribution (or “shape”) of any water-filled pore space and the length of current flow through it are the ultimate controls on resistivity.

Figure 15. The length of current flow through a water-saturated rock depends upon factors such as grain size, grain shape, sorting, and the presence of cementing minerals.



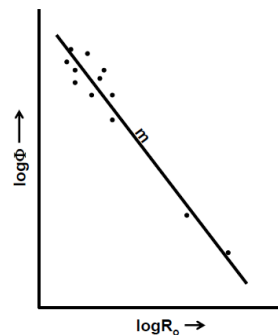
The shape of a rock's interconnected pore network is quantified by its tortuosity. For a water-saturated rock, tortuosity (τ) is a ratio of the length of current flow through the pore space to the linear distance traveled (Fig. 16). The longer the path traveled by current over a given length of rock, the greater its tortuosity.

Figure 16. Pore tortuosity reflects the length of current flow through a water-filled formation. The greater the tortuosity, the higher the measured resistivity.



Pore tortuosity is a rock property that cannot be measured, even from core samples. Because it exerts such an important control on resistivity, an appropriate and quantifiable parameter that can be used as a substitute for tortuosity is necessary if we are to better define the relationship between measured resistivity and porosity. Such a parameter can be determined by plotting the log of porosity in a water-saturated formation against the log of measured resistivity in that same formation (Fig. 17). Data points cluster along a line, and the slope of this line (m) is taken as a coefficient relating tortuosity to the measured resistivity of a formation at a given porosity.

Figure 17. For water-saturated formations, a log-log plot of porosity versus resistivity yields cementation exponent (m) which relates pore tortuosity to resistivity. R_o is the measured resistivity of a water-saturated formation.



Cementation exponent, unlike tortuosity, is a “measurable” quantity, but *not* a rock property. With core samples it can be derived experimentally, and how this is

accomplished will be discussed later. For now, it is only important to consider how cementation exponent (m) factors into the relationship between measured resistivity and porosity, expressed as follows:

$$R_{\text{meas}} \propto \frac{1}{\Phi^m}$$

Porosity and resistivity measured from core prove that R_{meas} is not equal to $1/\Phi^m$; it is only proportional. In fact, it was observed early on that the relationship did not work. However, rather than completely abandon the theoretically sound principle of pore tortuosity and its influence on measured resistivity, an additional parameter was introduced to essentially force-fit the relationship to empirical data. This parameter is called—confusingly enough—the tortuosity factor (a). Tortuosity factor is not a rock property. It is simply a factor that attempts to describe the non-linearity of empirical relationships observed between measured resistivity and porosity.

Taking into consideration both cementation exponent (m) and tortuosity factor (a), the relationship between measured resistivity and porosity is expressed

$$R_{\text{meas}} \propto \frac{a}{\Phi^m}$$

Fluid Saturations

The most often confused aspect of resistivity measurements is the influence of non-conductive hydrocarbons. While it is correct to say that an increasing volume of such non-conductive fluid in the pore space increases the measured resistivity of a rock, the true reason for this increase is often misunderstood.

The measured resistivity of a rock is inversely proportional to the fraction of its pore space that is filled with water. The higher the water saturation, the lower the resistivity. This relationship is expressed as follows:

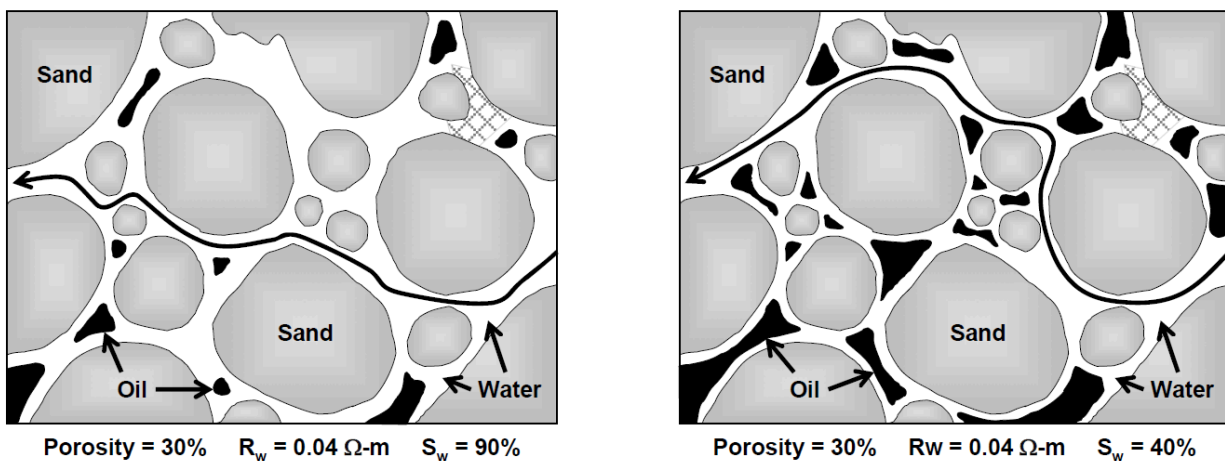
$$R_{\text{meas}} \propto \frac{1}{S_w}$$

Intuitive though it may seem, this equation does not adequately explain why some formations containing large amounts of effective pore space can produce

large volumes of oil and gas, yet still exhibit exceptionally low resistivities. Nor does it explain why some high porosity formations with very high resistivities produce only water. The key to understanding the effect of hydrocarbon on measured resistivity once again lies in a consideration of the length of current flow.

The distribution of a non-conductive fluid within the interconnected pore space of a rock affects the length of current flow and, accordingly, exerts a strong control on resistivity. Figure 18 illustrates the same rock at different water saturations. As the fraction of non-conductive hydrocarbon in the pore space increases (i.e., S_w decreases), the conductive path available to current flow becomes longer. Current flow must now wander around the non-conductive matrix and non-conductive fluid. Current flow tortuosity is increased, so resistivity must increase.

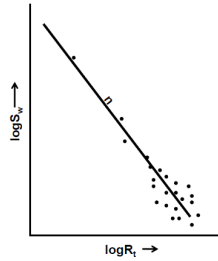
Figure 18. An increased fraction of non-conductive hydrocarbon in the pore space (i.e., decrease in S_w) increases a formation's resistivity due to an increase in current flow tortuosity.



As discussed previously, tortuosity is a non-measurable rock property. It makes no difference whether this tortuosity is caused by the complexity of a water-filled pore network or by the distribution of non-conductive fluids within that pore space; tortuosity remains an unknown. An appropriate parameter that can be substituted for this "fluid tortuosity" is necessary if we are to define a relationship between measured resistivity and the distribution of any non-conductive fluids. This parameter can be obtained by plotting the log of water saturation in a formation that contains hydrocarbon against the log of measured resistivity in that same formation (Fig. 19). Data points cluster along a line, and the slope of this line (n) is a

parameter describing the relationship between measured resistivity and the distribution of non-conductive fluids in the pore network.

Figure 19. For a formation containing hydrocarbon, a log-log plot of water saturation versus measured resistivity yields saturation exponent (n) which relates fluid distribution to resistivity. R_t is the true resistivity of such a formation, generally approximated by deep resistivity

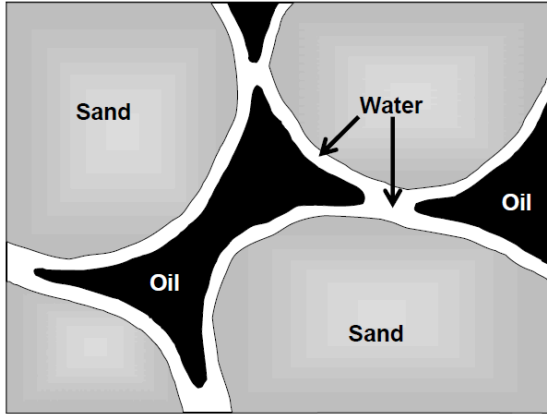


The parameter n is known as saturation exponent. A value for saturation exponent can be determined experimentally from core; however, if core is not available, then an assumption is required. The effect of water saturation (S_w) as a function of the distribution of non-conductive fluids on the measured value of resistivity is expressed as follows

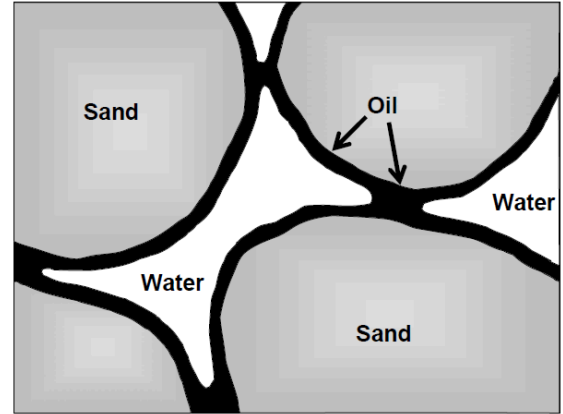
$$R_{\text{meas}} \propto \frac{1}{S_w^n}$$

The basis for assuming a value of saturation exponent (n) depends upon formation wettability. Wettability is the preference for one fluid (when in the presence of another) to adhere to grain surfaces of the matrix (Fig. 20). In formations containing both oil and water, “water-wet” refers to the condition in which water adheres to grain surfaces and oil exists as a discontinuous fluid phase. “Oil-wet” is where oil adheres to grain surfaces and water is the discontinuous fluid phase.

Figure 20. Wettability refers to the type of fluid adhering to grain surfaces of a rock (water or oil). The length of current flow through the conductive fluid (i.e., water) depends upon whether water is the continuous or discontinuous fluid phase.



Water-Wet Reservoir



Oil-Wet Reservoir

Applying the principle of resistivity as a function of the length of current flow, it can be demonstrated that water-wet formations typically (though not always) have lower resistivities than their oil-wet equivalents. This is because—all other factors considered equal—the length of current flow through the conductive fluid (i.e., water) depends upon whether it is the continuous or discontinuous fluid phase in the effective pore space. Most formations are water-wet, and the average saturation exponent (n) determined experimentally in these formations is approximately 2.0.

Putting It All Together

The measured resistivity of a formation is a function of five separate factors, and can be expressed by the three following relationships:

$$1. \quad R_{\text{meas}} \propto R_w$$

$$2. \quad R_{\text{meas}} \propto \frac{a}{\Phi^m}$$

$$3. \quad R_{\text{meas}} \propto \frac{1}{S_w^n}$$

Combining these three relationships results in the following expression:

$$R_{\text{meas}} = \frac{aR_w}{\Phi^m S_w^n}$$

What should be obvious from this relationship is that resistivity is not only a function of the amount of hydrocarbon present. In simplest terms, measured resistivity depends upon the resistivity of formation water and its distribution within an interconnected (effective) pore network. The distribution of water within effective pore space is influenced by the amount and distribution of non-conductive hydrocarbon; therefore, the resistivity measurement remains a good indicator of the presence of hydrocarbon. What must be remembered, however, is that other factors are at work.

Rt Versus Rxo

Measures of resistivity at different distances from the borehole in a porous and permeable formation respond to different fluids. For any formation, it can be assumed that the rock is homogeneous and that porosity near the borehole is equal to porosity far from the borehole. While this is not always a safe assumption (particularly in carbonates), it provides a starting point from which an investigation into the different types of fluids occupying that pore space can begin.

The uninvaded zone is that part of a formation farthest from the borehole, and which is not contaminated by the invasion of mud filtrate. Fluid types present in the uninvaded zone include original formation water and—hopefully—hydrocarbon. Ignoring any influence of the borehole on the accuracy of resistivity measurements, we can assume that a measure at some sufficiently deep depth of investigation approximates uninvaded zone resistivity (R_t). Therefore, R_t depends upon the resistivity of formation water (R_w), and the tortuosity of current flow through this water is in part determined by the amount and distribution of non-conductive hydrocarbon. This relationship is expressed as follows:

$$R_t = \frac{aR_w}{\Phi^m S_w^n}$$

The flushed zone is that portion of the invaded formation closest to the borehole, and extending only a few inches into the formation. Filtrate invasion within the flushed zone causes partial displacement of original formation water and

hydrocarbon (if present). Flushed zone resistivity (R_{xo}) depends upon the resistivity of the “water” in the pore space—here, a mixture of mud filtrate¹ (R_{mf}) and formation water (R_w)—and the tortuosity of current flow determined by the amount and distribution of non-conductive hydrocarbon remaining in the flushed zone after invasion (i.e., residual hydrocarbon).

Again ignoring any influence of the borehole on the accuracy of resistivity measurements, we can assume that a measure at a sufficiently shallow depth of investigation approximates R_{xo} . As water-based mud filtrate invades a formation, mud filtrate mixes with original formation water; therefore, R_{mf} might not adequately describe the resistivity of a mixture of both mud filtrate and original formation water. Nevertheless, the shallow resistivity measurement is often assumed to be an approximation of R_{xo} .

¹ For the purposes of this discussion, we are assuming that mud filtrate is water-based. Water-based mud filtrate is conductive and can, therefore, be distinguished from hydrocarbon on the basis of its resistivity. Oil-based mud filtrate, on the other hand, cannot be distinguished from formation hydrocarbon using a resistivity measurement, and evaluation of logs where it is used is slightly different from those where water-based mud filtrate is present.

Assuming a homogeneous formation and substituting resistivity terms, resistivity of the flushed zone (R_{xo}) is expressed as follows:

$$R_{xo} = \frac{aR_{mf}}{\Phi^m S_{xo}^n}$$

Where: R_{mf} = mud filtrate resistivity
 S_{xo} = flushed zone water saturation

Because shallow and deep resistivity measurements provide estimates of both R_t and R_{xo} , Equation 8 and Equation 9 can be solved for the variables of most interest to our clients—water saturations (S_w and S_{xo}). It is only with the benefit of resistivity measurements and additional information such as porosity, water salinity, and the complexity of the pore network that this is possible.

The Archie Water Saturation Model

Water saturation of the uninvaded zone (S_w) provides an indication of the relative proportions of water and hydrocarbon existing in the pore space. With a measure of deep resistivity, and assuming that it represents R_t , it can be solved for water saturation in a form that is referred to as the “Archie” equation:

$$S_w = \left(\frac{a}{\Phi^m} \times \frac{R_w}{R_t} \right)^{1/n}$$

Not all fluid existing in effective pore space is moveable. Some water and hydrocarbon is trapped in-place by surface adhesion, high capillary forces in small pore throats, high viscosity, or other causes. Because of this, water saturation of the uninvaded zone (S_w) calculated from Equation 10 does not provide a good indication of the relative proportions of fluids that will be produced from the formation. A water saturation of 20% does not mean the formation will produce 2 barrels of water for every 8 barrels of oil. It is simply an estimate of what the formation contains in the subsurface.

With a measure of shallow resistivity, and assuming that it represents R_{xo} , it then can be solved for water saturation of the flushed zone:

$$S_{xo} = \left(\frac{a}{\Phi^m} \times \frac{R_{mf}}{R_{xo}} \right)^{1/n}$$

Water saturation of the flushed zone (S_{xo}) helps answer the question of fluid moveability by its comparison with S_w . If $S_{xo} = S_w$, then it is an indication that hydrocarbon was not displaced by water-based mud filtrate during invasion and, therefore, is an indication that any hydrocarbon present is not moveable. On the other hand, if $S_{xo} > S_w$, then it is an indication that hydrocarbon was displaced by water-based mud filtrate during invasion, and that the hydrocarbon is producible (granted, the formation must be permeable and have sufficient pressure).

Limitations of the Archie Water Saturation Model

We often risk falling into a trap of placing too much trust in water saturation values calculated from the Archie equation. Much of this misconception results from a poor understanding of the assumptions involved. True, values for tortuosity factor (a), cementation exponent (m) and saturation exponent (n) might need to be assumed for lack of core data. However, other limiting assumptions of the Archie equation must also be kept in mind when using it to evaluate a formation's water saturation.

Clean Formation

The Archie model assumes a clean formation, meaning one that contains less than 10-15% shale- or clay-fraction. Physical properties of clay minerals cause total porosity estimates (i.e., cross-plot porosity) to be too high. In addition, because clays are actually conductive minerals, their presence causes our resistivity measurements to be lower than they would otherwise be. Using the Archie equation, higher porosity and lower resistivity equates with more water. Therefore, the Archie equation produces S_w results that are too high in shaly formations.

Single Water Phase

The Archie model assumes only a single phase of formation water and does not distinguish between water that is producible (or "free") and water that is irreducible (or "bound"). All formations contain at least some volume of water, part of which is free to produce and the remainder of which is trapped by surface adhesion or capillary forces. Very fine-grained reservoirs can have high water saturations, but might produce very little water. This is because a large percentage of that total water is trapped within the small pores. The Archie equations "sees water as water," and thus provides an estimate of the total water saturation of a clean formation.

Effective Pore Space

The controls on measured resistivity discussed to this point have all assumed that any pore space present is interconnected, so it should come as no surprise that the Archie model relies upon this same assumption. The presence of isolated pore space in a rock results in high resistivities because current flows along a very tortuous path (if it flows at all). In clean formations containing isolated pores, S_w results from the Archie equation are often too low.

Water-Wet Formation

Finally, the Archie model assumes the formation is water-wet. A saturation exponent (n) of 2.0 reflects the effect of fluid tortuosity on resistivity under average water-wet conditions. In oil-wet formations, S_w results from the Archie equation are in error.

Determining Tortuosity Factor (a) and Cementation Exponent (m)

One obvious concern when estimating water saturation is the reliability of tortuosity factor (a) and cementation exponent (m) values. The importance of core samples in the process of evaluating a formation's producibility can best be exemplified by considering how these parameters are determined when core samples are available.

The relationship between resistivity and the porosity of a formation is adequately described by the following equation. Measured resistivity is a function of the amount of pore space and its tortuosity. Suppose that a core sample is available and that all original formation fluids existing in its pore space can be evacuated. Porosity of the core sample can then be measured by one of several standard methods.

The evacuated pore space of this core sample can then be saturated with a brine of known salinity (i.e., known R_w). The resistivity of the water-saturated core sample (R_o) is then expressed as follows:

$$R_o = \frac{a}{\Phi^m} \times R_w$$

If porosity and formation water resistivity (R_w) are known, then cementation exponent (m) can be solved by holding tortuosity factor (a) constant. The constant chosen for tortuosity factor is usually 1.0, which is based on the assumption of an inverse linear relationship between resistivity and porosity. Using such a method, tortuosity factor and cementation exponent are determined experimentally from core samples. Rotary sidewall cores often provide samples of sufficient size to perform such analyses.

But what if a core sample is not available? After all, whole coring is a costly investment, and wireline coring poses certain risks and associated costs. Values for

tortuosity factor and cementation exponent must still be obtained so water saturation of the formation can be evaluated.

Assumptions are required in the absence of core-derived data. The most commonly assumed values for tortuosity factor and cementation exponent are illustrated in Figure 21. The basis for these assumptions is experimental studies of core data, so there is at least some validity in their use. However, assumed values might not be appropriate for the formation you are evaluating, and the potential uncertainty resulting from their use must be kept in mind.

Figure 21. Typically assumed values of tortuosity factor (a) and cementation exponent (m).

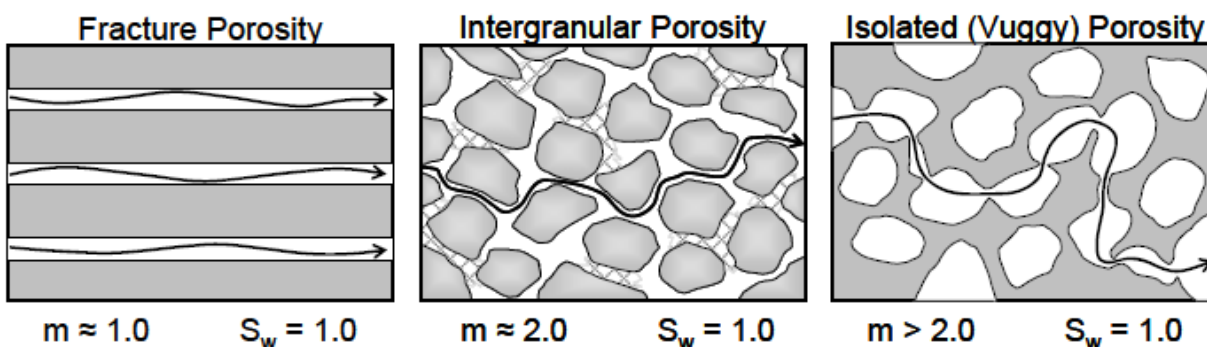
		Sandstones		
		Carbonates		
			$\phi > 16\%$	$\phi < 16\%$
a	1.0		0.62	0.81
m	2.0		2.15	2.0
		Unconsolidated	Consolidated	

The most important things to keep in mind when assuming tortuosity factor (a) and cementation exponent (m) are that the values listed in Figure 9 represent clean formations containing effective porosity. Where these conditions are not met, the assumptions are inappropriate, and there is not a reliable method for predicting their values in those instances. Make the most reasonable assumptions based on the information available to you, but also realize the potential for uncertainty in your saturation estimates.

An understanding of the practical meaning of cementation exponent values as they apply to pore tortuosity becomes important later in the qualitative interpretation of resistivity logs. Figure 22 illustrates how cementation exponent (m) varies as a function of pore tortuosity. Cementation exponent itself does not depend upon the additional tortuosity of current flow caused by the distribution of

any non-conductive hydrocarbon. That “fluid tortuosity” is quantified by the saturation exponent, as discussed earlier.

Figure 22. Cementation exponent (m) varies as a function of pore tortuosity. In the illustrated rocks, pore space is water-saturated; therefore, current flow tortuosity is only a function of pore tortuosity



Determining Formation Water Resistivity (R_w)

Oddly enough, the most important reservoir fluid in the evaluation of fluid saturations is not hydrocarbon, but water. Water—whether salty or what we consider to be “fresh”—supports the flow of current through interconnected pore space, thereby allowing the finite resistivities of rocks to be measured. Any current flow through a clean, shale-free formation occurs in water, and not in rock matrix or hydrocarbon. Water’s ability to conduct current is proportional to its salinity, and saltwater, with its high concentration of dissolved solids, is a better conductor than fresh water. Both saltwater and fresh water are, of course, better conductors than matrix or hydrocarbon.

Formation water resistivity (R_w) is a critical variable in estimating water saturation. While small errors in R_w might not cause critical uncertainty in S_w , larger errors in R_w can make the difference between deciding to complete or abandon a potential reservoir. A value of R_w that is too high causes us to overestimate the amount of water present (i.e., higher S_w), and one possible result might be to overlook a hydrocarbon-producing formation because we believe it contains too much water. On the other hand, a value of R_w that is too low can cause us to become interested in a formation that contains a large volume of water, but not enough hydrocarbon to be economic.

There are many potential sources of formation water resistivity (R_w), the most accurate of which tend to be water samples taken from the formation of

interest. These samples can be collected by formation testers such as SFTT and RDT, by drill-stem tests (DST), or might even be produced water. Each source has its distinct advantages and disadvantages. Water catalogs are another potential source in many geographic regions where measured R_w values have been archived over the years. These cataloged R_w values are derived from actual water samples, so their use is subject to the limitations of whatever method was used to collect them. In many cases, where a water sample or water catalog is not available, it might be acceptable to assume some commonly used R_w for the particular geographic region.

Resistivity and porosity measurements on logs can also be used to derive R_w when no other source is available, or when it is desirable to cross-check values from those of another source. While there are several methods for estimating R_w from logs, the most straightforward approach involves using resistivity and porosity responses to qualitatively identify a formation that obviously contains water, and then assuming that it is completely water saturated ($S_w = 100\%$).

For a water-saturated formation, R_w is solved as follows:

$$R_o = \frac{\Phi^m \times R_t}{a}$$

Although the accuracy of R_w results obtained from the previous equation certainly depends upon the validity of resistivity and porosity data, there is somewhat of a “safety factor” build into this method. By assuming that the formation is completely water saturated, it is unlikely that your calculation will yield a value that is lower than the true R_w in a clean formation.

While it is common practice to estimate R_w using the previous where no other source is available, you must keep in mind that its use is subject to the same limiting assumptions as the Archie equation (e.g., clean formation, effective porosity, single water phase, and water-wet conditions). The primary limiting assumption is that the formation in which you calculate R_w is completely saturated ($S_w = 100\%$). Only when these conditions are met does the method provide reliable values for R_w .

Further Insight into the Archie Water Saturation Model

There are many controls on the measured true resistivity (R_t) of a formation, of this there can be little doubt. These controls include:

1. Porosity of the rock, because matrix (generally speaking) is non-conductive. The larger the proportion of matrix to pore fluid (i.e., the lower the porosity), the more resistive the rock.
2. The relative proportions of non-conductive fluids (hydrocarbon) to conductive fluids (water) occupying that pore space. This is to say that, as water saturation decreases (i.e., more hydrocarbon), the more resistive the rock.
3. The salinity of the water in the pore space. The lower its salinity, the more resistive the rock.
4. Any geologic property of the matrix itself (i.e., grain shape, grain size distribution, the presence of isolated pores, etc.) that influences the tortuosity of current flow through the rock. The more tortuous the path, the more resistive the rock.

All of these relationships are taken into consideration when using the Archie equation for estimating water saturation in a hydrocarbon reservoir. But how accurate is our knowledge of these relationships? What is the mathematic basis for making them, and what influences do our assumptions have on the results? A look at the evolution of the porosity-resistivity relationship which serves as the basis for the Archie equation provides some perspective on this problem.

In the 1930s, resistivity logs were readily available, but porosity logs did not yet exist. The porosity of a rock was only known where core was available and it could be measured. The difficult task of interpreting the cause of high resistivities observed on primitive logs was made even more difficult by this lack of porosity information. Was the observed increase in resistivity caused by the presence of hydrocarbon? Or was such an increase the result of lower porosity, fresher water, or any of the other factors that influence current flow tortuosity?

Gus Archie was an engineer who set out in 1942 to find some relationship between porosity and resistivity so that this decision might be made easier. The data for his research included 72 core samples from a sandstone reservoir in Louisiana. These 72 samples became the basis for an equation that has been used since 1942 to estimate the water saturation of hydrocarbon reservoirs worldwide, and it is an equation that is certainly not without its own limitations.

To begin with, the resistivity of a completely water-saturated rock (R_o) is some function of the rock's porosity (Φ) and the resistivity of water (R_w) filling that pore space. This can be expressed in simple form as:

$$R_o = F_r \times R_w$$

Formation resistivity factor (F_r) is a multiplier that must take into account both the effect of the amount of pore space (Φ) and the tortuosity of that water-filled pore space on the rock's measured resistivity (R_o). By rearranging the previous equation, F_r can be solved for in terms of resistivity as follows:

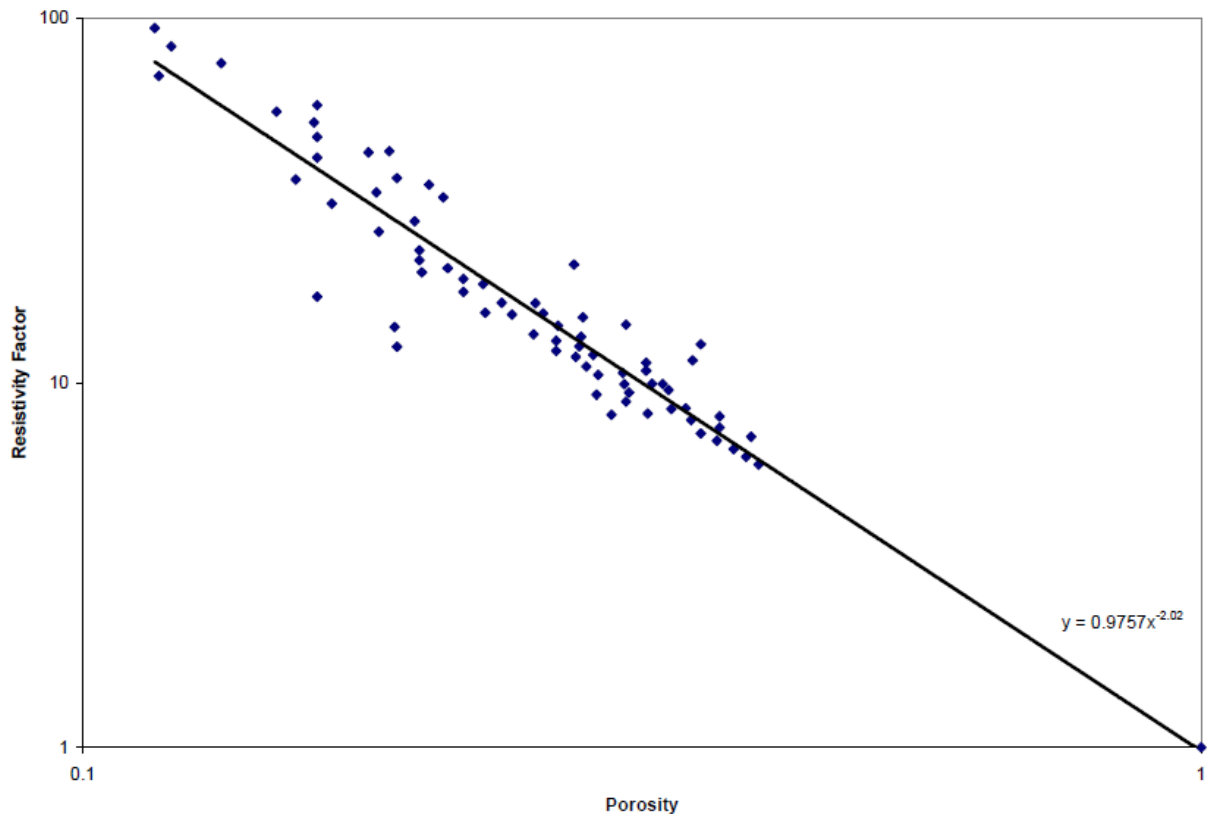
$$F_r = \frac{R_o}{R_w}$$

A fundamental condition of this equation is that, if $\Phi = 1$, then $F_r = 1$. For a saturated rock at $\Phi = 1$ (i.e., an open volume of water), its measured resistivity (R_o) depends solely upon the resistivity of the water (R_w) and nothing more. Therefore, $R_o = R_w$, and $F_r = 1$.

From his 72 core samples, Archie was able to measure their porosities. Furthermore, after saturating their pore space with a brine of known salinity (i.e., known R_w), he was able to measure their resistivities (R_o). Thus equipped with values of Φ and F_r for each of his 72 samples, Archie began his search for a simple relationship (emphasis on simple) between porosity and resistivity that might make the task of interpreting resistivity logs in the absence of porosity data from core somewhat easier. Keep in mind, however, that Archie's data were from samples collected in one field in the state of Louisiana.

With the technology available to him at the time, and given the probability that most engineers then were equipped with a ready supply of log and semi-log graph paper instead of graphic calculators and computers, Archie discovered just such a simple relationship by plotting the log of F_r versus the log of Φ . His original data from this Louisiana sandstone are illustrated in Figure 23.

Figure 23. Log-log plot of Archie's (1942) original porosity-resistivity data, including the physical requirement that $F_r = 1$ when $\Phi = 1$.



The simple relationship that Archie thereby discovered can be expressed in the following general form:

$$F_r = a\Phi^{-m}$$

For Archie's dataset, he found that $a = 0.9757$ and $m = 2.02$. Therefore, using approximations for these values, he concluded that $a = 1$ and $m = 2$. In his defense, it should be noted that Archie made the following remark concerning his findings: "It should be remembered that the equations given are not precise and represent only approximate relationships."

Because there was no alternate theory at the time, Archie's porosity-relationship from 72 core samples of a Louisiana sandstone was quickly put to use in the interpretation of resistivity logs. The result of this "herd mentality" was that now it was possible to quantify the effects of porosity on resistivity and, therefore, be able to use resistivity logs to estimate water saturation. The Archie

relationship was no doubt applied worldwide and, as to be expected, there were instances in which it was discovered that empirical data did not fit his model.

Ten years later, Winsauer et al. (1952) revisited Archie's initial porosity-resistivity relationship and expanded the model to include data collected in sandstone reservoirs from around the world. Winsauer proposed that, if the physical requirement $F_r = 1$ when $\Phi = 1$ is relaxed, then empirical data would better fit Archie's $F_r = a\Phi^m$ relationship, where a is not necessarily equal to 1. By doing so, Winsauer discovered in the new dataset that $a = 0.62$ and $m = 2.15$. Herd mentality once again prevailed. Because the new dataset used by Winsauer came from geographically diverse reservoirs, many accepted $a = 0.62$ and $m = 2.15$ as "universal values," and began applying this relationship when quantifying the effects of porosity on resistivity. (Notice that $a = 0.62$ and $m = 2.15$ requires a negative value for F_r which, by definition, is impossible because $F_r = R_o/R_w$ (see Equation 15). A resistivity ratio cannot be negative!)

Over time, just as had been the case with Archie's original values of $a = 1$ and $m = 2$, it was discovered that empirical data did not necessarily fit the $a = 0.62$ and $m = 2.15$ values of Winsauer et al. It appeared that there were no "universal" values of a and m that could satisfy the $F_r = a\Phi^m$ relationship in all instances. Instead, values for a and m appeared to differ in all cases and, therefore, needed to be customized for each dataset. This means that every core sample has unique values for a and m . Regardless of this fact, however, the simple $F_r = a\Phi^m$ relationship formulated by Archie and Winsauer remains today the basis for using logging measurements of resistivity and porosity to estimate water saturations of hydrocarbon reservoirs worldwide. Obviously, what to use as values of a and m in these reservoirs is a major consideration in the accuracy of those estimates.

There are some fundamental physical flaws in the simple $F_r = a\Phi^m$ relationship of Archie-Winsauer, however. One important point to make is that, if $\Phi = 1$, then $F_r = a$, which is only correct for the special case $a = 1$. It is necessary, then, to consider the following possible conditions which negate the simple relationship:

1. For rocks with homogeneous porosity, the presence of cementing minerals causes a higher rate of porosity reduction as grain size decreases. If water-filled pore space is the conductive path through those rocks, then the rocks cease to conduct when that path is broken; meaning, a rock can become infinitely resistive before porosity reaches zero. This would be the case in a rock with only isolated pore space, a condition that might certainly exist in a fine-grained rock where very small pores are made isolated by cementing minerals (and definitely so in the

theoretical “Swiss-cheese” rock). In other words, it is entirely possible that $Fr = 1$ when $\Phi < 1$, which is not possible according to the simple $Fr = a\Phi^{-m}$ relationship.

2. Some rocks, because of the conductive nature of certain minerals present, might continue to be conductive even after porosity reaches zero. This would be the case in shaly sandstones, where clay minerals are conductive. Even at a porosity of zero, these formations remain conductive. In other words, it is entirely possible that $Fr = 1$ when porosity is some finite value other than 1 (or, more practically, Fr is negative). This is not possible according to the simple $Fr = a\Phi^{-m}$ relationship. Such a negative value of Fr is precisely what Winsauer et al. discovered to be the case in their dataset.

What to do?!

There is a starting point to every interpretation problem and, for lack of information, assumptions are necessary. You must start somewhere. The theoretically sound principle of the simple $Fr = a\Phi^{-m}$ relationship remains in wide use today. Where core is not available, it is standard practice to assume values for a and m (Fig. 24). The most widely assumed sets of these variables include the “Archie parameters” ($a = 1$, $m = 2$) and the “Humble parameters” ($a = 0.62$, $m = 2.15$; Winsauer was an employee of Humble Oil at the time of his research).

Figure 24. Commonly assumed values for a and m . These parameters have since become widely known as “tortuosity factor” and “cementation exponent,” respectively.

		Sandstones	
		$\phi > 16\%$	$\phi < 16\%$
a	Carbonates	1.0	0.62
		0.62	0.81
m		2.15	2.0
		Unconsolidated	Consolidated

From Figure 24, notice that “Archie parameters” ($a = 1$, $m = 2$) are often assumed for carbonate reservoirs. At first glance this is confusing, considering the

fact that Archie's research was conducted in a sandstone reservoir. In carbonates, however, there is a greater likelihood of finding isolated pores, in which case $F_r = 1$ when porosity is some finite value other than 1 (i.e., the rock becomes non-conductive before zero porosity is reached). In such rocks, empirical data shows wide variation in a and m values. Because of this expected variation in those rocks, and as a sort of "default," it is common practice to assume the fundamental Archie relationship ($a = 1$, $m = 2$) for lack of any other data to the contrary. This is the reason why it is critical to know the pore type when evaluating carbonate reservoirs. Current flow tortuosity in these rocks depends greatly upon pore type, and F_r depends upon factors which represent this tortuosity (i.e., a and m). The availability of core allows us to determine a and m in these reservoirs, and more accurately quantify the relationship between porosity and resistivity in them.

Also notice from Figure 22 that, for sandstones, it is common practice to assume values for a and m based upon their porosity. "Humble parameters" ($a = 0.62$, $m = 2.15$) are oftentimes used for higher porosity sandstones, while "Tixier parameters" ($a = 0.81$, $m = 2.0$) are assumed for lower porosity sandstones. These values are based upon the results obtained from two datasets; therefore, it is not necessarily more correct to select one set of assumptions in favor of the other. For that matter, is it necessarily any more correct to select Humble or Tixier parameters in favor of Archie parameters in these sandstones?

By now you might be entirely skeptical – if not completely disbelieving – of the accuracy of water saturation estimates made from logs. If so, then your doubts are justified. However, you can take some minor amount of comfort in knowing that water saturation estimates using log data are accurate enough if the correct assumptions are made. How do we know when we have made the correct assumptions? To answer that question requires more information: more information means more data, and more data means more cost.

Regardless of the uncertainties resulting from the use of assumptions and a relationship based on two unique datasets, the simple $F_r = a\Phi^m$ relationship remains theoretically sound. However, from this discussion, it becomes apparent that four things must always be kept in mind when applying the Archie equation for estimating water saturation. These include:

1. The simple porosity-resistivity relationship does not work for rocks that contain isolated pores, because those rocks cease being conductive before porosity reaches zero. Isolated pores are more common in carbonates than

in siliciclastic rocks (i.e., “sands”), so the Archie equation should be used with extreme caution in carbonates.

2. The simple porosity-resistivity relationship does not work for rocks that contain conductive clay minerals, because these rocks remain conductive even after porosity reaches zero. Therefore, the Archie equation should be used with extreme caution in shaly formations.

3. The simple porosity-resistivity relationship is valid only when a and m are custom-defined for a particular dataset. In this respect, every reservoir is unique, and there are no universal values of a and m .

4. The simple porosity-resistivity relationship is based upon core samples in which the limits of porosity are 10% at a minimum and 40% at a maximum. Even in “ideal” Archie conditions (i.e., clean sandstones in which all porosity is interconnected), water saturations for porosities outside of these limits should be treated with caution.

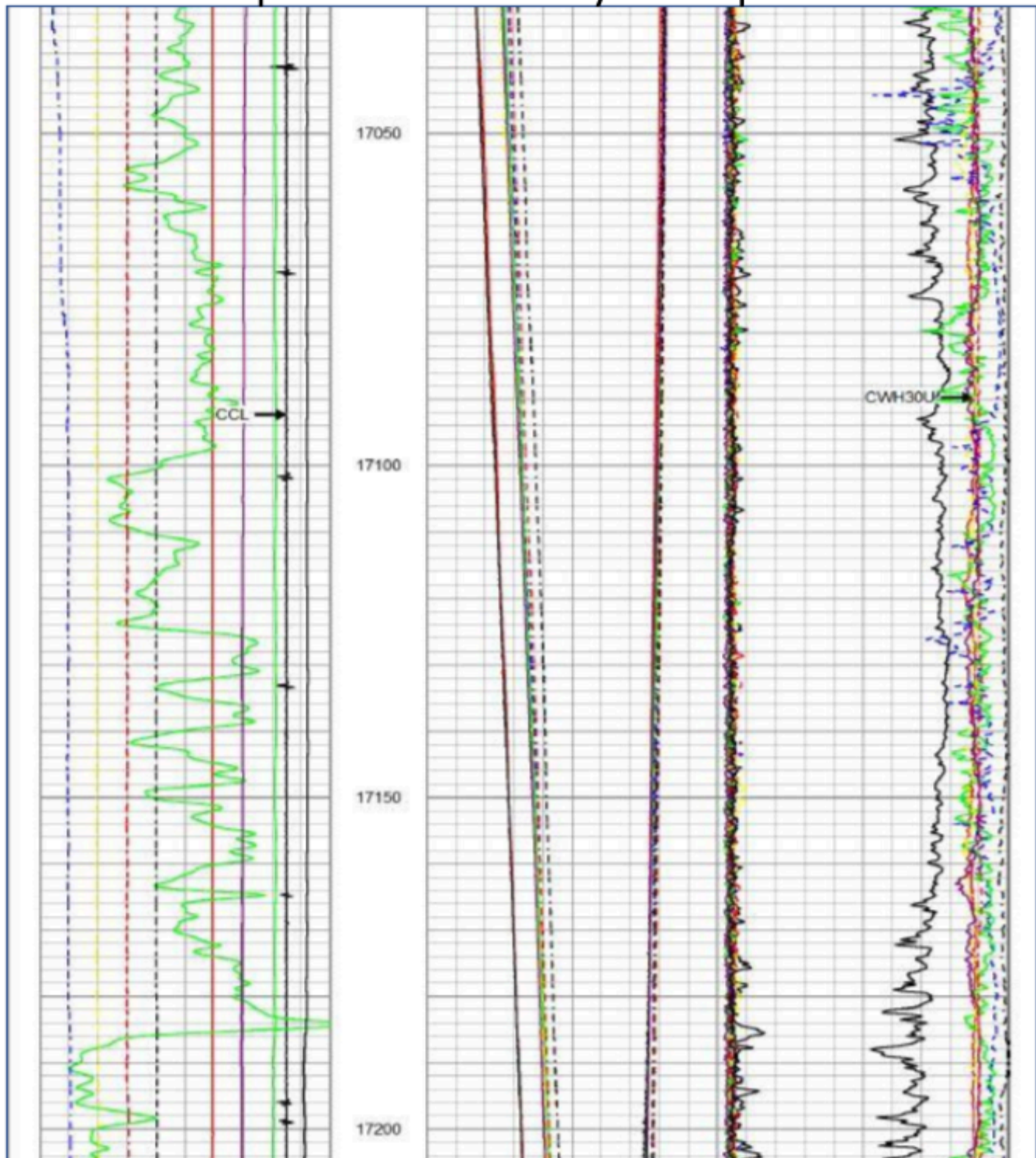
The Danger in Calculating Values of Water Saturation

Armed with little more than an idea of lithology and measurements of resistivity and porosity, it is possible to calculate the water saturation (S_w) of a clean formation using the Archie equation. It becomes the simple task of reading values from a log, assuming some parameters, plugging them into the equation, and calculating a result. However, this is where our evaluation of a formation’s producibility can become anything but simple. A common oversight is to calculate S_w and blindly accept it as valid. Very little thought might be given to matrix and fluid properties that influence the log measurements (especially resistivity). Oftentimes, the validity of assumptions is never questioned, and the possibility of uncertainty is rarely considered.

Our failure to recognize how both matrix- and fluid-related properties affect log measurements, and our reluctance to consider how uncertainty and error result from assumptions and calculations, can quickly lead to mistakes in log interpretation. Once a formation is completed and its production confirms what was predicted by our interpretation of the data, the venture is considered a success and everyone’s confidence in their interpretation abilities grows. However, when a formation’s production seems to contradict our evaluation, then the accuracy of the log data—rather than the accuracy of our interpretation of them—is often called into question.

By the time poor log quality, oversights, mistakes and uncertainty are recognized, it might be too late to take any remedial action. Production casing might have already been set, or the well might have already been plugged. The effective interpretation of a formation's producibility requires a thorough understanding of the measurements, variables, assumptions and calculations involved in the process.

Chapter 3 - Resistivity Tools part II

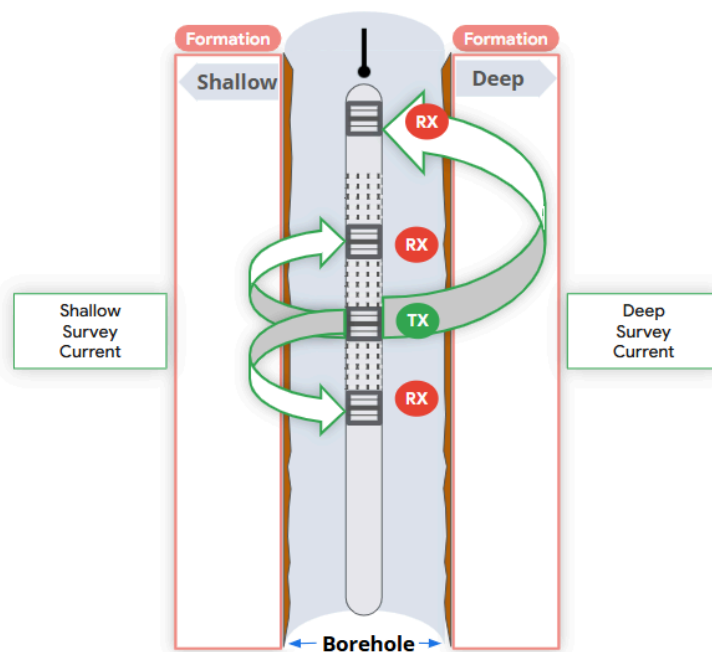


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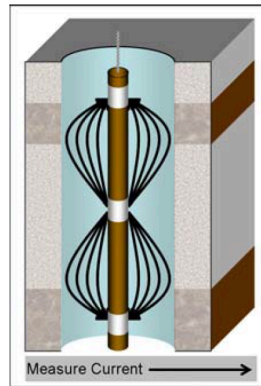
Chapter 4 - Laterolog

Figure 1. Schematic of an electrode device array showing the flow of measure current (MC).



The borehole presents a unique problem for electrode tools. If the borehole is highly conductive, then measure current (MC) travels the path of least resistance directly up the borehole and to the current return electrode (Fig. 2). In such a situation, an electrode tool would provide only a measure of borehole resistivity.

Figure 2. In highly conductive boreholes, measured current would simply follow the path of least resistance up the mud column.

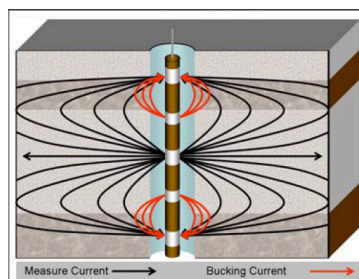


To overcome this problem, electrode tools use the concept of focusing to ensure that measured current (MC) passes through the borehole and into the formation.

Digital Focusing versus Dynamic Focusing

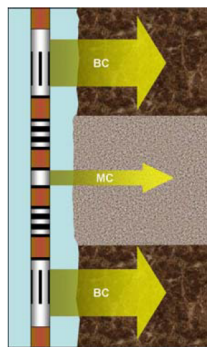
Laterologs emit bucking current (BC) from electrodes on the tool (Fig. 3). The purpose of this bucking current is to drive the measured current through the borehole fluid and into the formation. The bucking current also prevents measure current from traveling into low-resistivity shoulder beds above and below the formation of interest.

Figure 3. Traditional focused devices simultaneously emit measure current and bucking current.



With traditional focused electrode devices, a set of monitor electrodes on the tool senses imbalances between measure and bucking currents. This provides feedback to the tool's electronics so that bucking current can either be increased or decreased to achieve balance with measured current (Fig. 4). These dynamically focused electrode tools are very complex and expensive to manufacture.

Figure 4. Traditional focused electrode devices simultaneously emit bucking current (BC) to keep measure current (MC) constrained within a zone of interest.

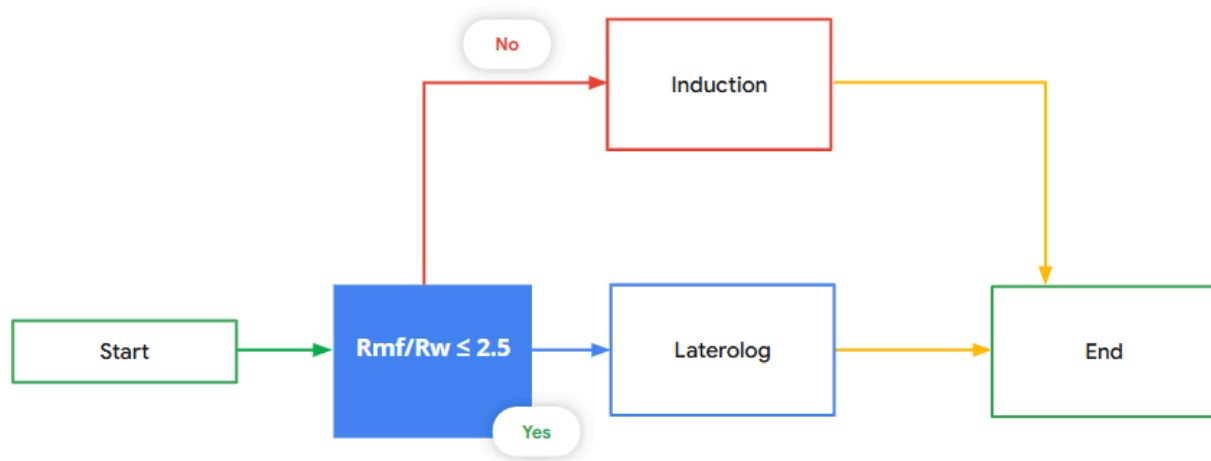


The primary objective of logging a laterolog is to determine a value for true resistivity (R_t)

Logging Conditions

Unlike Induction Tools which are commonly logged in fresh water-based mud and non-conductive boreholes, a laterolog tool is designed to achieve best results in highly conductive borehole fluids. Highly conductive saltwater-based drilling fluids are common in areas where water soluble evaporite minerals (e.g., halite, anhydrite, etc.) are encountered during drilling. In saltwater-based drilling fluids, the borehole effect would be too large for an induction tool to provide an accurate measure of formation resistivity. The laterolog provides accurate results in these conditions where there is low contrast between the salinity of mud filtrate and the salinity of formation water.

Figure 5. Preferred operating environments for resistivity tools.

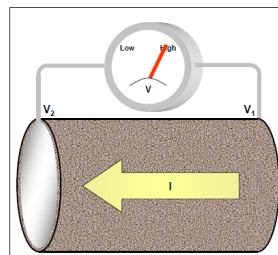


The Laterolog cannot provide accurate results in oil-based mud or air-filled boreholes.

Physics of the Measurement

The measurement principle of the laterolog relates to Ohm's law, which describes the resistivity of a material in terms of current flow and voltage drop. This concept is simply demonstrated using a cylindrical core sample of porous rock that is completely saturated with conductive saline water (Fig. 6). Metallic electrodes are placed on both ends of the rock, and are attached to a voltmeter.

Figure 6. Ohm's law allows resistivity to be calculated from a measure of current and voltage.



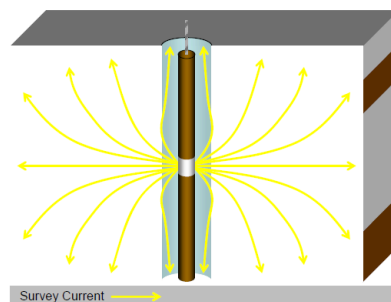
Current flowing through the rock creates a potential difference (voltage) between the electrodes. Measures of current and voltage, together with an idea about the geometry of the current flow, are used to calculate the rock's resistivity according to Ohm's law.

$$R = K \frac{V_1 - V_2}{I} = K \frac{V}{I}$$

Where: R = resistivity
K = a factor related to current flow geometry
V = voltage drop between two electrodes
I = current

One problem in using this concept to determine the resistivities of subsurface formations lies in defining current flow geometry. In the example above using a core sample, current flow geometry is defined by the shape of the sample (i.e., cylindrical). On the other hand, current flow through thick and laterally extensive subsurface formations is unconstrained by formation shape (Fig. 7). The laterolog must be designed so that current flow geometry is known and constant in order to measure accurate values of formation resistivity.

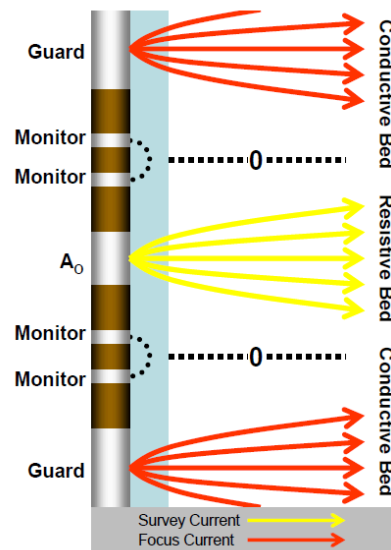
Figure 7. Unconstrained current flow would present problems to measuring formation resistivity.



Basic Electrode Array and Function

In a dynamically focused laterolog. A set of monitor electrodes positioned along the sonde senses imbalances between survey and focus currents (Fig. 8). These monitors provide feedback to the tool's electronics so that focus current can either be increased or decreased to achieve balance with survey current.

Figure 8. Monitor electrodes ensure a balance between survey current and focus current.



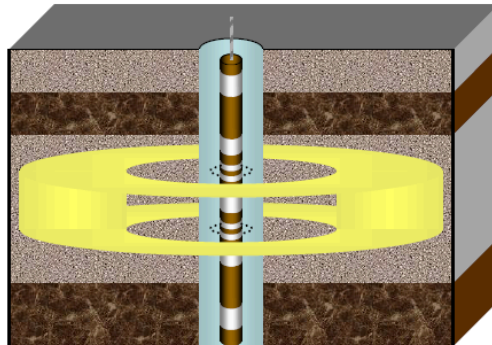
Monitor electrodes ensure that a zero-potential difference exists between survey current and focus current. Under such a condition, survey current flow is constrained to the formation of interest. Therefore, current flow geometry is constant and defined by the electrode array, so formation resistivity can be determined by Ohm's law.

Current Flow

On our generic tool used to describe how a laterolog works, all electrodes are carefully positioned symmetrically along the sonde in order to create a well-defined and constant current flow geometry in the formation. With such a symmetrical

arrangement, current flow geometry is constrained to a cylinder (Fig. 9). The geometry of the current flow through the formation is important for computing its resistivity.

Figure 9. Cylindrical current flow geometry resulting from electrode placement.

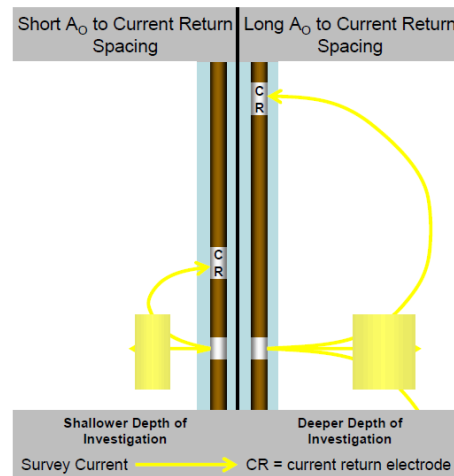


The dimensions of the cylindrical current flow geometry also define the tool's vertical resolution and depth of investigation. Vertical resolution of the measurement is controlled by the placement of electrodes along the sonde. Depth of investigation, on the other hand, is influenced by tool design factors that include:

- Distance from AO electrode to current return electrode
- Length of guard electrodes
- Survey current frequency

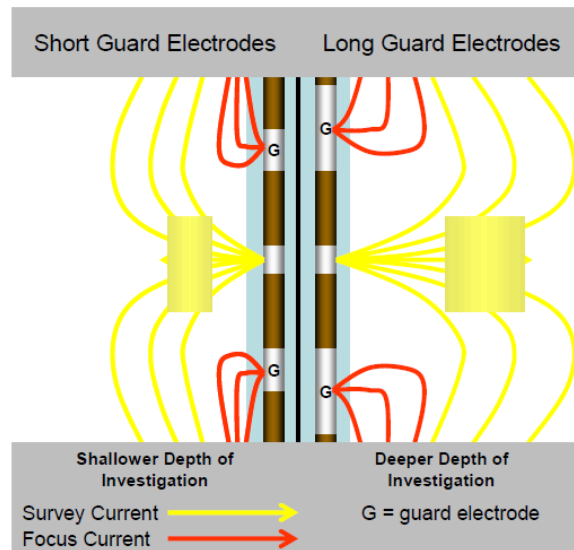
The greater the distance between the AO and current return electrodes, the deeper into the formation survey current is able to flow (Fig. 10). Shallow depths of investigation require short AO to current return spacings, while deeper depths of investigation require longer spacings. Focus current ensures that vertical resolution remains constant for different electrode spacings by defining a constant current flow geometry.

Figure 10. Depth of investigation is influenced by the spacing between AO and current return electrodes.



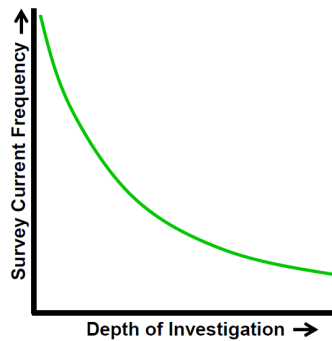
The longer the guard electrodes, the better able focus current is at driving survey current deeper into the formation (Fig. 11). Longer guard electrodes yield deeper depths of investigation. Reducing guard length reduces a measurement's depth of investigation.

Figure 11. Depth of investigation is influenced by the length of guard electrodes.



Depth of investigation is also inversely proportional to the survey current frequency (Fig. 12). The lower the frequency, the deeper the depth of investigation, and vice versa.

Figure 12. Depth of investigation is influenced by survey current frequency.



Multiple depths of investigation can be achieved simultaneously by designing a tool to emit “dual” survey currents at different harmonic frequencies (Fig. 13). The laterolog operates using two harmonic survey current frequencies to simultaneously produce measures of shallow resistivity and deep resistivity

Shallow and deep laterolog measurements utilize a common set of electrodes to maintain current flow in a cylindrical shape of constant thickness; therefore, vertical resolutions of the two measurements are identical. However, different AO to current return spacings and guard lengths produce different depths of investigation

Figure 13. Survey current and focus current paths for deep and shallow measurements

