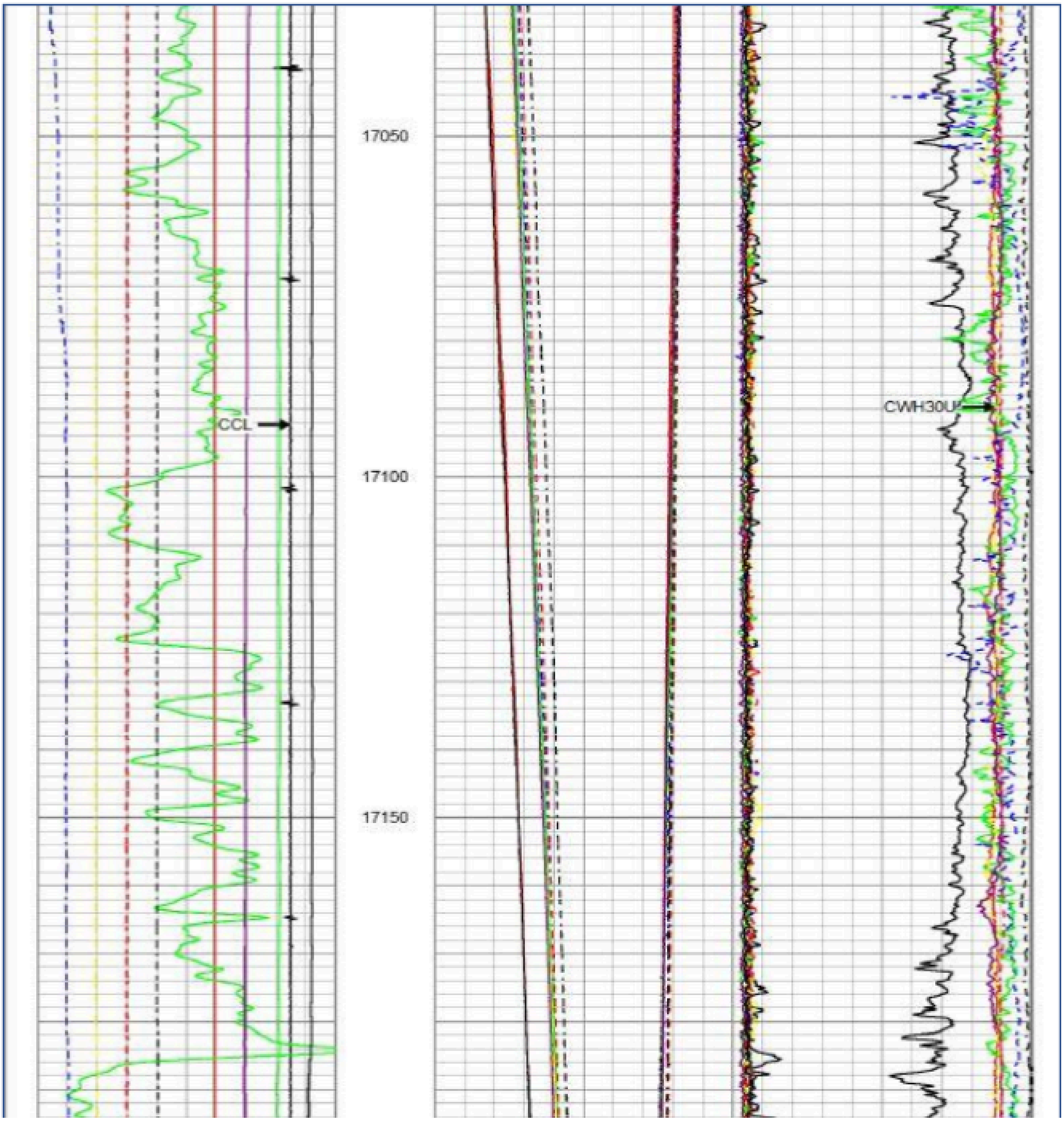
Chapter 7 - Acoustic Porosity



Content

Chapter 7 – Acoustic Porosity

The Acoustic Porosity Tool is designed to record and digitize the energy spectrum of acoustic waves propagated through the borehole and formation. The Acoustic Porosity Tool transmitter generates an acoustic impulse—sound—that travels through the borehole and formation as a variety of different wave types. Each of these acoustic waves travels at a different velocity. The type of acoustic wave generated and its velocity are functions of the mechanical properties of the media through which it travels.

Mechanical energy traveling through the borehole and formation as acoustic waves is detected by a set of receivers positioned some distance from the transmitter. The energy spectrum—or waveform—detected at each receiver is then digitized for transmission uphole. From these digitized waveforms, compressional wave and shear wave velocities as well as other information can be extracted for use in a number of formation evaluation applications. Post-processing of digitized waveforms to acquire this information is performed away from the wellsite at a computing center.

Applications

The primary objective of acquiring acoustic waveforms with the Acoustic Porosity Tool is to determine the velocities of compressional and shear waves through the formation. The velocities of these waves depend upon the elastic properties and bulk density of the formation. Compressional and shear wave velocities are used in the following applications of acoustic logs:

- Porosity determination
- Lithology identification
- Identification of formations containing gas
- Provide depth correlation for seismic sections

A particularly beneficial application of compressional and shear wave velocities is the estimation of rock elastic properties such as Poisson's ratio, Young's modulus, shear modulus, and bulk compressibility. These rock elastic properties are important in the design of drilling, completion, and production enhancement programs, and can be used to:

• Estimate formation strength and least horizontal stress for the purpose of determining borehole stability and formation sanding potential

• Predict the extent of induced hydraulic fractures

Rock properties applications also require the integration of other logging measurements, such as bulk density. In addition, information extracted from digitized waveforms can be used to:

• Create synthetic seismograms

• Detect the presence of natural fractures

• Indicate permeability variations versus depth

Logging Conditions

The monopole acoustic tool is capable of recording acoustic waveforms only in liquid-filled boreholes.

Such environments include:

• Fresh water-based mud

• Saltwater-based mud

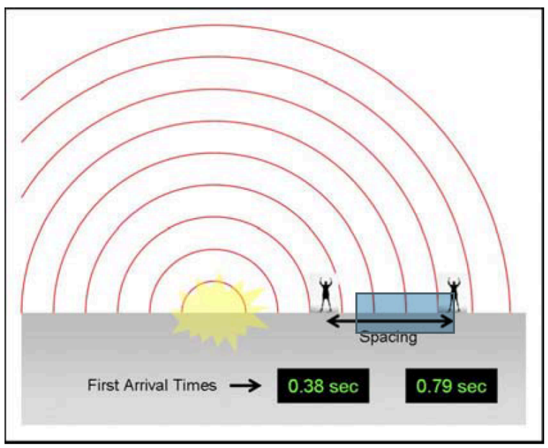
• Oil-based mud

Using a specific toolstring configuration, the Acoustic Porosity Tool is capable of acquiring acoustic information in cased hole. The Acoustic Porosity Tool—as well as all other acoustic services—cannot be used to acquire data in air-filled boreholes.

Physics of the Measurement

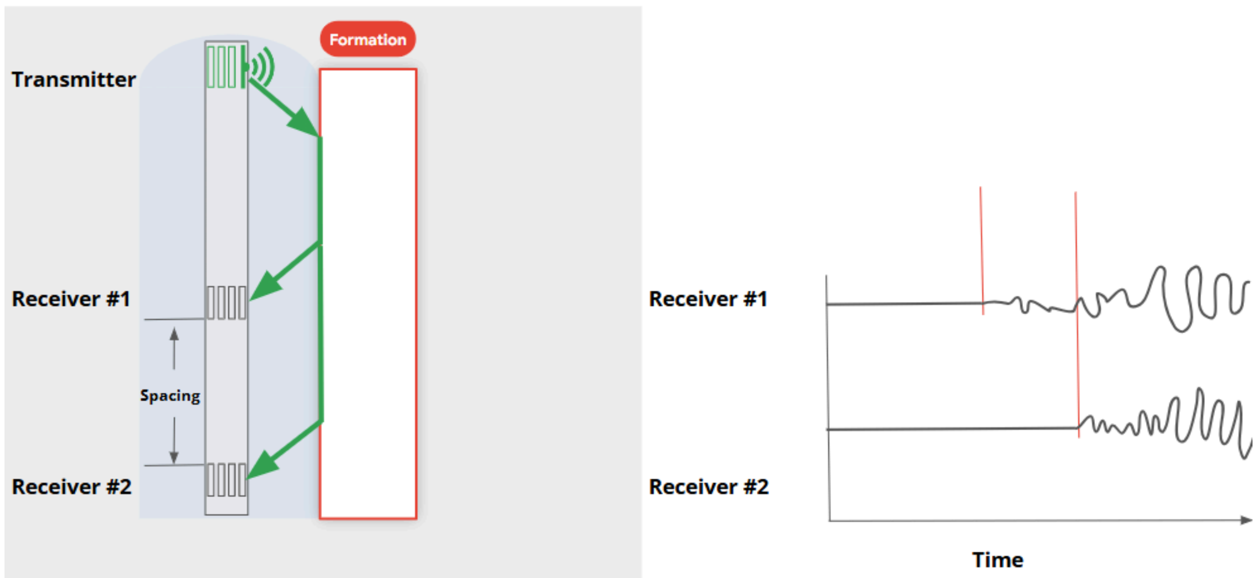
The velocity of any acoustic wave can be determined from the time difference between its first arrivals at two or more receivers. A simple analogy of this technique involves two persons standing different distances from the point of an explosion. Acoustic energy ("sound") generated by the explosion will reach their ears at different times. If the distance between the two persons—or spacing—is known, then the velocity of the acoustic wave over the interval between them can be calculated. This principle is illustrated in Figure 1).

Figure 1. First arrival can be thought of as the time elapsed between an explosion and the sound it generates reaching a person's ears.



As applied to the monopole acoustic tool, the principle is identical (Fig. 2). The tool's transmitter generates an acoustic impulse that is propagated through the borehole and formation. From waveforms recorded at two or more receivers, the time difference between first arrivals of any acoustic wave can be determined.

Figure 2. First arrivals at two acoustic receivers.



Because the spacing between these receivers is fixed, the velocity of an acoustic wave can be calculated as follows:

$$V = \frac{\text{spacing}}{\text{time difference}}$$

Where: spacing = physical distance between two receivers (feet)
time difference = difference in arrival times at two receivers (seconds)

Generating and Recording Acoustic Energy

The Acoustic Porosity Tool employs a monopole transmitter. This transmitter is a lead metabionate piezoelectric crystal (Fig. 3) that converts an electrical impulse into mechanical energy. Current applied intermittently to the transmitter causes the material from which it is made to rapidly expand and contract.

Figure 3. Piezoelectric transmitter used in a Acoustic Porosity Tool.

The mechanical energy created by each transmitter pulse generates a laterally omnidirectional pressure wave that radiates outward in all directions through the borehole fluid. The omnidirectional nature of this fluid pressure wave is characteristic of a monopole transmitter. With each transmitter pulse every 400 milliseconds, several types of acoustic waves are propagated up and down the borehole and through the formation. These waves each travel at different velocities, and include:

- Two direct waves, one of which travels along the tool housing (tool mode) and the other through the drilling fluid (mud wave).
- Two body waves (compressional and shear) which travel through the “body” of the formation.
- Three surface waves (leaky mode, normal mode, and Stoneley) which travel along the interface between the borehole and the formation.

Acoustic waves traveling through the borehole and formation eventually pass a set of four receivers that serve exactly the opposite function as the transmitter. These conical piezoelectric crystals (Fig. 4) detect mechanical energy of the passing acoustic wave and convert it into an electrical signal.

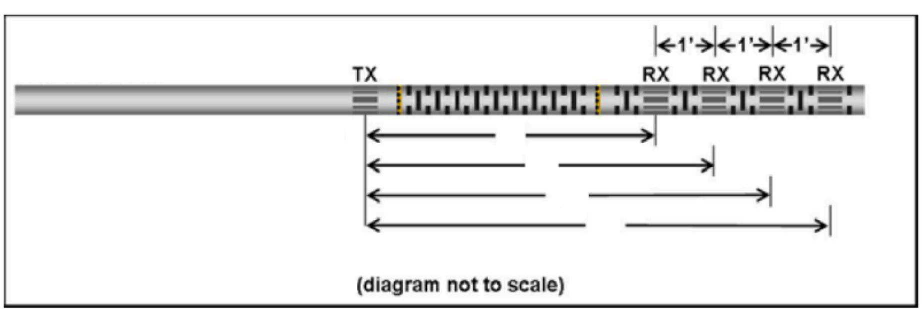
Figure 4. One of four conical piezoelectric receivers used by the Acoustic Porosity Tool.

To determine the velocity of any acoustic wave, that wave must be detected by at least two receivers. The time elapsed (or travel time) from transmitter pulse to an acoustic wave arriving at a receiver depends upon its velocity through the medium or media between the transmitter and receiver. The greater the velocity, the shorter the travel time, and vice versa.

The first arrival of any acoustic wave is the earliest time at which it is detected at a receiver. Each wave type generated by a transmitter pulse travels at a different velocity. Accordingly, each wave type arrives at different times at multiple receivers spaced some distance apart.

The four receivers used by the Acoustic Porosity Tool show in the following image are positioned at different distances from the transmitter (Fig. 5). The transmitter-to-receiver distance is known as offset. With increased offset, travel times of acoustic waves from transmitter to receiver are increased. The practical advantage of such a long offset is greater time separation between acoustic waves traveling at different velocities, thus making their first arrivals at a receiver easy to distinguish.

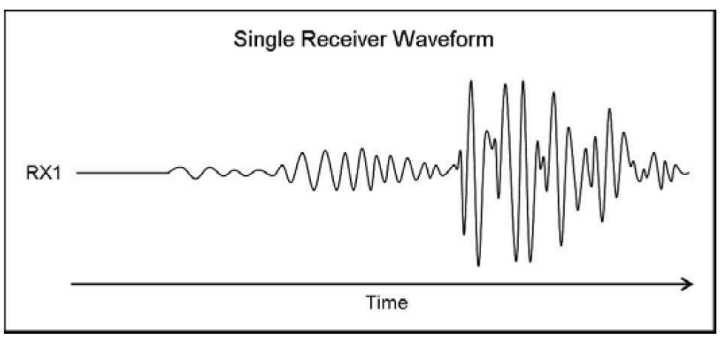
Figure 5. Offsets and spacing of the Acoustic Porosity Tool receivers.



Detected Acoustic Waveforms

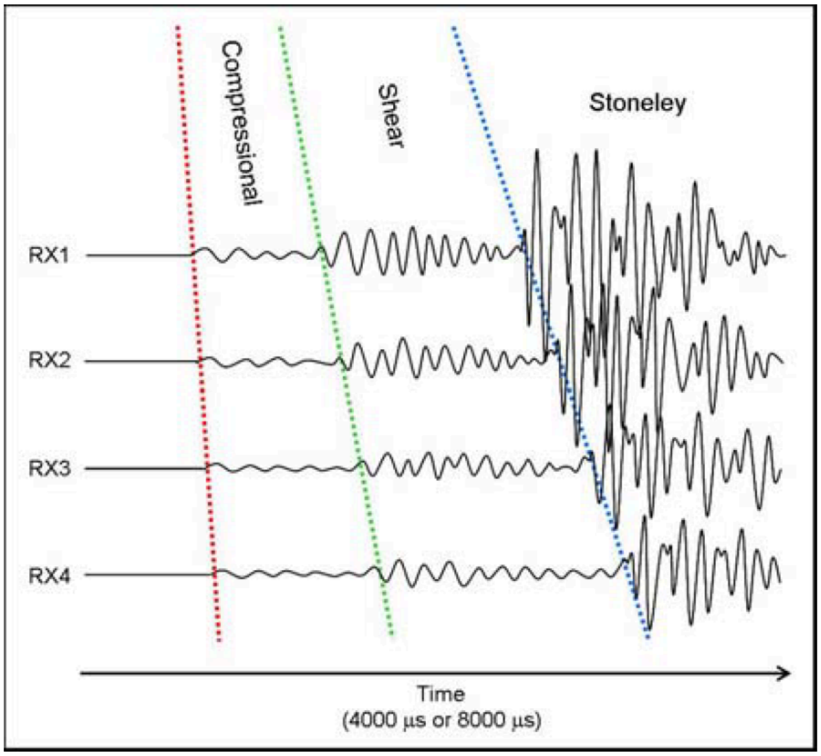
As acoustic waves pass a receiver, they generate an electrical signal representing the composite energies of all wave types versus time. This signal is sample and the electrical signal is digitized for presentation as an acoustic waveform. With each transmitter pulse, one waveform (Fig. 6) is digitized at each receiver for a total of four waveforms recorded per transmitter pulse.

Figure 6. An acoustic waveform recorded at one of the Acoustic Porosity Tool receivers.



All acoustic wave types contribute to detected energies; however, three distinct regions appear on waveforms which represent the arrivals of compressional, shear, and Stoneley waves (Fig. 7). Velocities of these waves are determined from the time difference between their first arrivals at two or more receivers. Other important characteristics of the waveforms, such as frequency and amplitude, can be used to estimate formation properties such as degree of consolidation, presence of natural fractures, and—in the case of Stoneley waves—permeability variations versus depth.

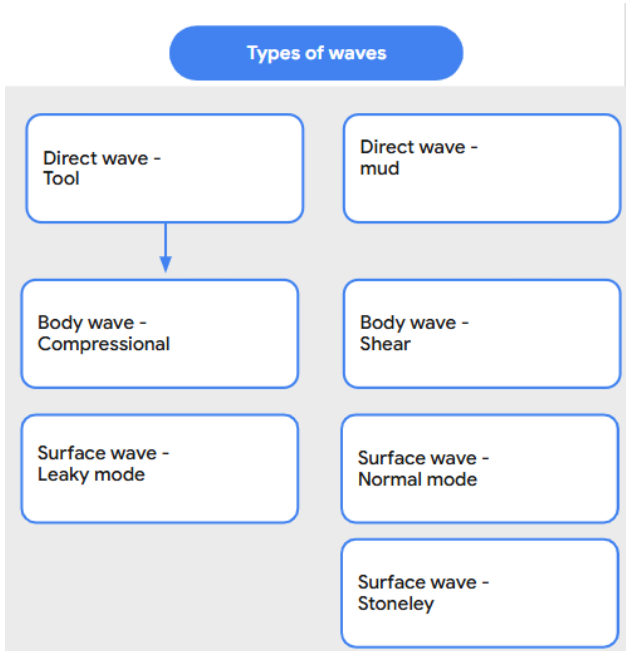
Figure 7. Composite waveforms recorded at four Acoustic Porosity Tool receivers.



Acoustic Wave Types

Propagation of acoustic energy through the borehole and formation is a complicated event and requires closer examination of the characteristics and usefulness of each of the wave types created. Several different wave types are created by each transmitter pulse (Fig. 8).

Figure 8. Wave types created by firing of the Acoustic Porosity Tool transmitter.



Direct Waves

Direct waves are those that travel directly from the transmitter to the receiver. Because these waves are not propagated through the formation, they are not characteristic of formation properties and are, therefore, undesirable.

Direct waves include:

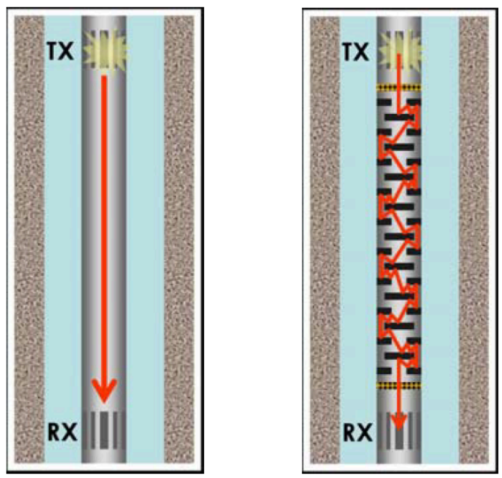
- Tool mode waves
- Mud waves

Tool Mode Waves

The most direct path by which acoustic waves can travel from transmitter to receiver is along the tool housing. These waves are referred to as tool mode and travel at the velocity of the material from which the tool housing is constructed. Because of their very short travel times, tool mode waves would be the first to arrive at a receiver and would interfere with the ability to detect the more important early first arrivals of acoustic waves traveling through the formation.

Slots machined into the tool housing between transmitter and receiver increase the length of the path that tool mode waves travel (some other tools use a rubber). While these slots do not change the velocity of tool mode waves, they do dramatically increase their travel time. These slots ensure that the first arrival at a receiver is that of an acoustic wave propagated through the formation, and not along the tool housing.

Figure 9. Tool mode waves (left) would present a problem to detecting compressional waves, but their interference is eliminated by slotted tool housings (right).

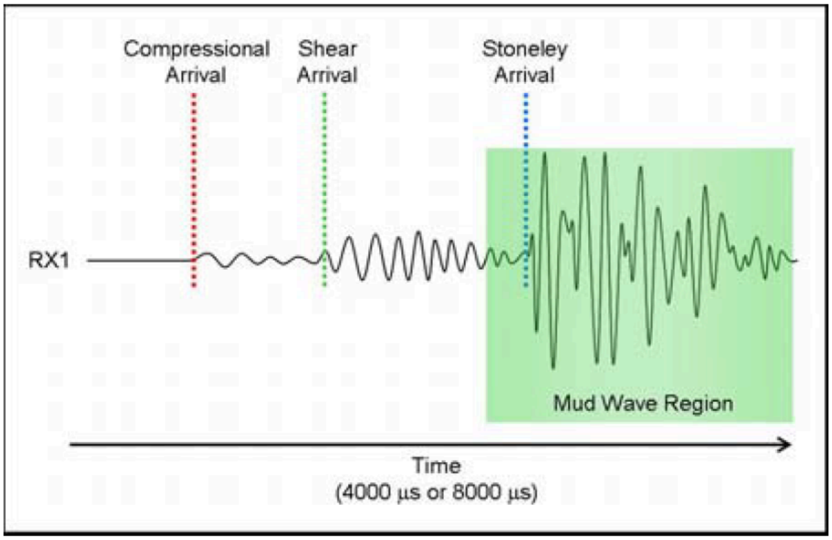


Mud Waves

Another direct path by which acoustic energy can travel from transmitter to receiver is through the drilling fluid. These waves are referred to as mud waves, and travel at the velocity of the borehole fluid. Acoustic velocity through a liquid is much slower than through a rigid formation. Therefore, mud waves have long travel times. These long travel times ensure that mud wave arrivals at a receiver do not interfere with more important and much earlier arrivals of those waves propagated through the borehole and formation.

Although mud wave arrivals coincide with Stoneley arrivals, their amplitudes are so small that they pose little problem with Stoneley detection (Fig. 10).

Figure 10. Mud wave arrivals occur much later in time than important formation arrivals.



Body Waves

Body waves are those that travel through the “body” of the formation and, as such, are among the most important of acoustic wave types. These waves are generated as the fluid pressure wave traveling through the borehole strikes the borehole wall. Acoustic energy is refracted into the formation at some angle depending upon the velocity of the fluid pressure wave through the borehole fluid, its incident angle at the borehole wall, and the velocity of the refracted acoustic wave. The energies of body waves traveling through the formation are radiated back into the borehole as fluid pressure waves that are then detected by a receiver.

The time difference between the fluid pressure wave arrivals at two or more receivers is used to compute the body wave velocity through the formation. These velocities are, in turn, used to derive important formation properties such as porosity and rock elastic constants. The relative velocities and amplitudes of body waves can also be used as indicators of formation lithology, degree of consolidation, and to identify naturally fractured formations.

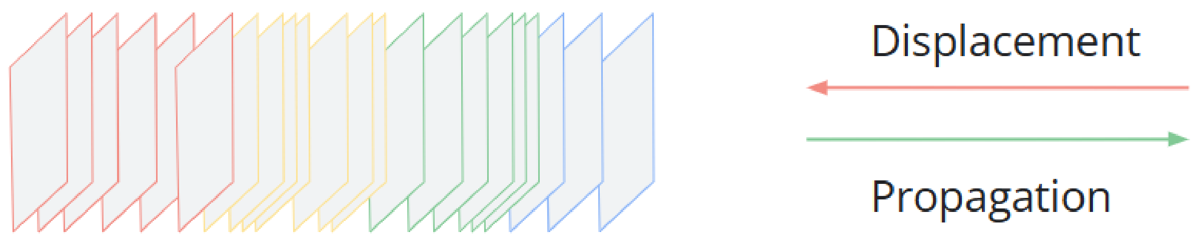
Body waves include:

• Compressional waves (P-waves)
• Shear waves (S-waves)

Compressional Waves (P-waves)

Compressional waves are crated as the fluid pressure wave traveling through the borehole fluid impinges upon the borehole wall, causing deformation of the rock and its pore fluids on a molecular level. As molecules of the rock and fluid are deformed, compressional energy causes them to vibrate in a direction parallel to the direction of energy propagation (Fig. 11). This energy is re-radiated into the borehole as compressional waves travel through the formation, and the resulting fluid pressure wave in the borehole is then detected at a receiver.

Figure 11. Schematic of molecular deformation caused by a compressional wave.



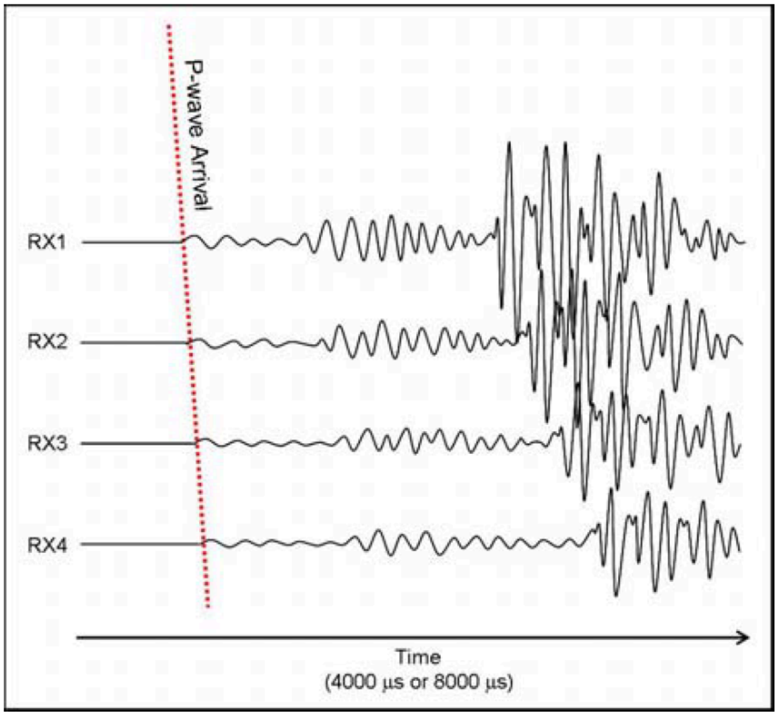
Compressional wave velocity is a function of the elastic properties and bulk density of the medium through which it travels. This is represented in the following equation:

$$V_P = \left[\frac{K + \frac{4}{3} G}{\rho} \right]^{1/2}$$

Where: V_P = velocity of the compressional wave (ft/sec)
K = bulk modulus of medium
G = shear modulus of medium
ρ = bulk density of medium

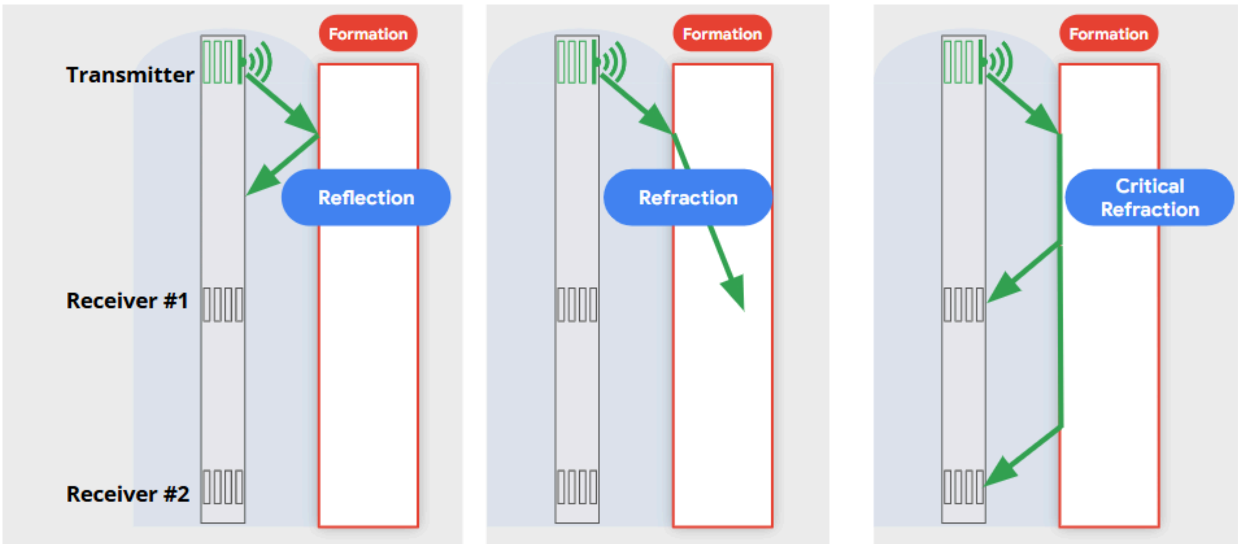
Compressional waves are the fastest body wave and, therefore, the first to arrive at any receiver (Fig. 12). For this reason, they are often referred to as P-waves (primary). Compressional waves have the ability of traveling through liquids as well as solids.

Figure 12. Compressional waves (P-waves) are the first to arrive at any receiver.



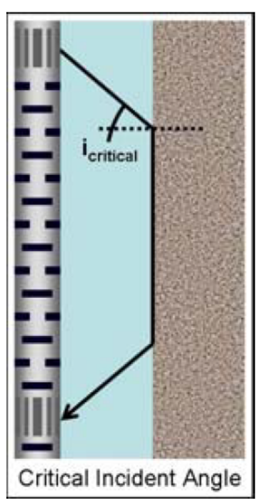
When the incident fluid pressure wave traveling through the borehole impinges upon the borehole wall, compressional waves are either reflected back into the borehole or refracted into the formation (Fig. 13). The angle through which acoustic energy is redirected is a function of the incident angle of the fluid pressure wave at the borehole wall, its velocity through the borehole fluid, and the velocity of the compressional wave through the formation.

Figure 13. Compressional energy is either reflected or refracted at the borehole wall.



At some incident angle (icritical) compressional energy is critically refracted along the borehole wall and at a very shallow depth within the formation (Fig. 14). Because this path represents the path of minimum travel time between transmitter and receiver, the first compressional wave to arrive at any receiver is one that has been critically refracted.

Figure 14. Critically refracted compressional waves are the first to arrive at a receiver.



While a compressional wave is critically refracted through the formation, its energy is re-radiated into the borehole in the form of a fluid pressure wave. The time difference between first arrivals of this fluid pressure wave at two or more receivers is used to compute compressional wave velocity through a length of formation equivalent to receiver spacing (1-foot). Figure 15 illustrates a comparison of critically refracted compressional wave velocities in example formations to that of the fluid pressure wave traveling in a borehole filled with different drilling fluids. Note that compressional wave velocity decreases in more unconsolidated formations.

Figure 15. Example P-wave velocities.

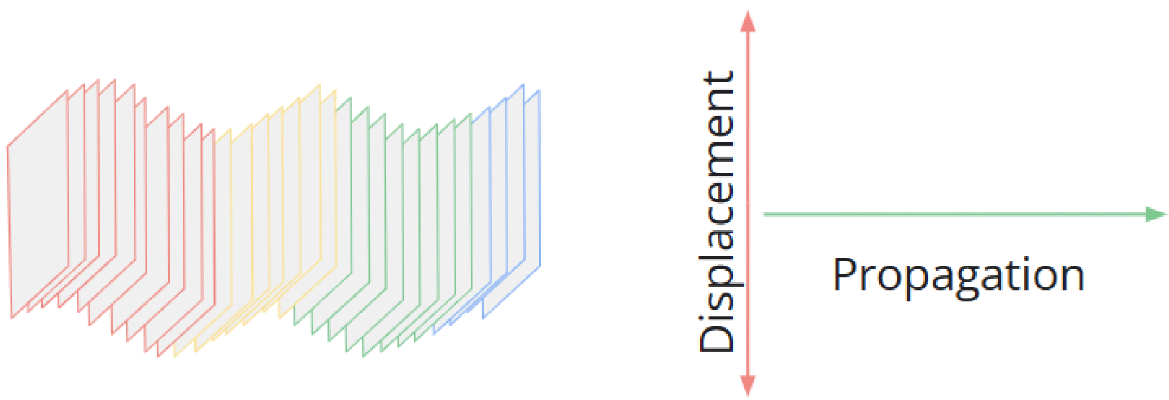
Formation	V_p (ft/sec)	Δt_c (μsec/ft)
Dolomite (at 0% porosity)	22989	43.5
Limestone(at 0% porosity)	21008	47.6
Quartz sandstone (at 0% porosity)	18018	55.5
Consolidated shale	14285	70
Unconsolidated shale	7143	140
Assumed drilling fluid	$V_{mud\ wave}$ (ft/sec)	Δt_c (μsec/ft)
Fresh water-based mud	5291	189
Saltwater-based mud	5405	185
Oil-based-mud	4878	205

Shear Waves (S-waves)

Like compressional waves, shear waves are also created as the fluid pressure wave impinges upon the borehole wall, but the resulting molecular deformation occurs only within the rock and not the pore fluids. Fluids do not support shear deformation. As molecules of the rock are deformed, shear energy causes them to vibrate in a direction perpendicular to the direction of energy propagation (Fig. 16).

Shear energy traveling through the formation is re-radiated into the borehole, and the resulting fluid pressure wave is then detected at a receiver.

Figure 16. Schematic of molecular deformation caused by a shear wave.



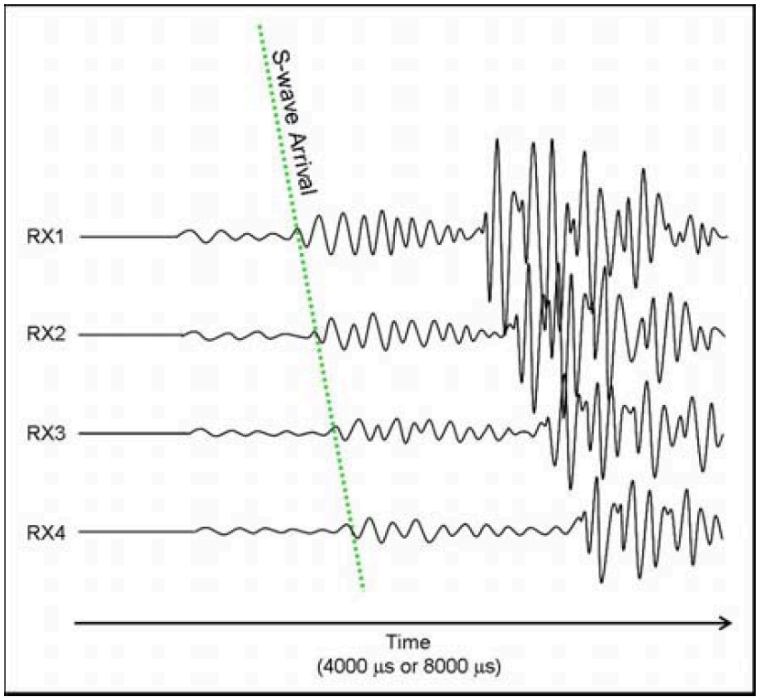
Shear wave velocity is also a function of the elastic properties and bulk density of the medium through which it travels.

$$V_S = \left[\frac{G}{\rho}\right]^{1/2}$$

Where: V_S = velocity of the shear wave (ft/sec)
G = shear modulus of medium
ρ = bulk density of medium

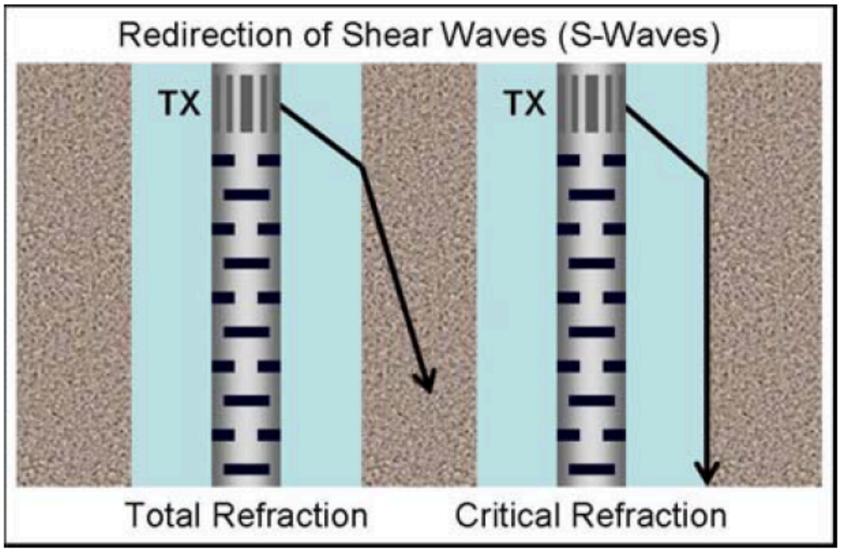
Shear waves travel at about 50% to 70% the velocity of compressional waves, depending upon the formation's degree of consolidation and its porosity. This means that shear waves are the second body wave to arrive at a receiver (Fig. 17) and, for this reason, are often referred to as S-waves (secondary). Shear waves only travel through solids. They will not propagate through liquids where shear modulus is zero (G = 0).

Figure 17. Shear waves (S-waves) are the second to arrive at any receiver.



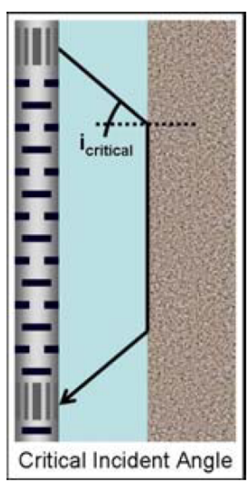
When the incident fluid pressure wave impinges upon the borehole wall, it may either be reflected back into the borehole or be refracted into the formation as a shear wave (Fig. 18). Once again, the angle through which this energy is redirected is a function of the incident angle, the velocity of the fluid pressure wave through the borehole, and the shear wave velocity through the formation.

Figure 18. The redirection of shear waves (S-waves) created by a fluid pressure wave striking the borehole wall. Notice that shear waves are not reflected.



As was the case with compressional waves, at some incident angle (icritical) shear energy is critically refracted along the borehole wall and at a very shallow depth within the formation (Fig. 19). The first arrival of a shear wave at a receiver represents one that has been critically refracted; that is, it followed the path of minimum travel time between transmitter and receiver.

Figure 19. Critically refracted shear waves are the second to arrive at a receiver.



Because shear waves cannot travel through fluid, the acoustic energy detected at a receiver and used to compute their velocity is not actually a shear wave. Critically refracted shear waves cause energy to be re-radiated into the borehole in the form of a fluid pressure wave. The time difference between first arrivals of this fluid pressure wave at two or more receivers is used to compute shear wave velocity through a length of formation equivalent to receiver spacing.

Figure 20 illustrates a comparison of the fastest possible critically refracted shear wave velocities (at 70% of compressional velocity) in example formations to that of the fluid pressure wave traveling in a borehole filled with different drilling fluids. Note that, as was the case with compressional waves, shear wave velocity decreases in more unconsolidated formations.

Figure 20. Example S-wave velocities.

Formation	$V_{s\text{-wave}}$ (ft/sec)
Dolomite (at 0% porosity)	16420
Limestone(at 0% porosity)	15006
Quartz sandstone (at 0% porosity)	12870
Consolidated shale	10204
Unconsolidated shale	5102
Assumed drilling fluid	$\text{fluid}_{\text{wave}}$ (ft/sec)
Fresh water-based mud	5291
Saltwater-based mud	5405
Oil-based-mud	4878

Shear Waves in Slow Formations

One limitation of the monopole Acoustic Porosity Tool transmitter is that it might fail to generate critically refracted shear waves in formations with very slow velocities. If no shear wave is critically refracted, then shear wave velocities necessary for rock properties applications cannot be determined from the digitized waveforms. Remember, rock elastic properties are important in the design of drilling, completion, and production enhancement programs. Rock properties can be used to:

• Estimate formation strength and least horizontal stress for the purpose of determining

borehole stability and formation sanding potential.

• Predict the vertical extent of induced hydraulic fractures.

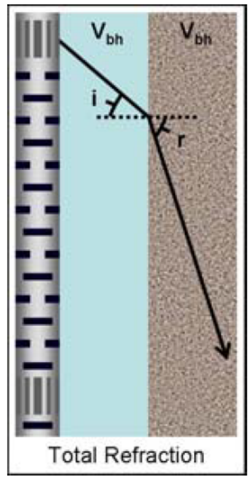
When the fluid pressure wave created by a monopole transmitter pulse impinges upon the borehole wall, acoustic energy is either reflected back into the borehole or refracted into the formation. The angle through which this energy is redirected is a function of the incident angle of the fluid pressure wave at the borehole wall, its velocity through the borehole fluid, and the velocity of the refracted energy through the formation.

The redirection of energy across the interface between two materials can be described by Snell's law (Fig. 21), which states:

$$\frac{\sin i}{\sin r} = \frac{V_{bh}}{V_{fm}}$$

Where: i = incident angle of fluid pressure wave at the borehole wall
r = refracted angle of acoustic energy within the formation
V_{bh} = velocity of the fluid pressure wave through the borehole
V_{fm} = velocity of refracted acoustic energy through the formation

Figure 21. Snell's law can be used to describe the redirection of energy at the borehole wall.



The first arrival detected at a receiver represents an acoustic wave that has been critically refracted along the borehole wall and at a shallow depth within the formation. Critical refraction occurs when the refracted angle (r) equals 90º. Therefore, the incident angle required for critical refraction to occur is determined by the following relationship:

$$\arcsin i_{critical} = \frac{V_{bh}}{V_{fm}}$$

Where: $i_{critical}$ = incident angle required for critical refractionl
V_{bh} = velocity of the fluid pressure wave through the borehole
V_{fm} = velocity of refracted acoustic energy through the formation

By definition, the sine of any angle cannot be greater than 1.0. Therefore, for critical refraction of acoustic energy to occur (Fig. 22), the ratio Vbh/Vfm must be less than 1.0. This is to say that the velocity of acoustic energy through the formation must be faster than the velocity of the fluid pressure wave through the borehole. If not, then critical refraction is impossible.

Figure 22. Critical refraction (r = 90º) occurs at some incident angle, icritical.

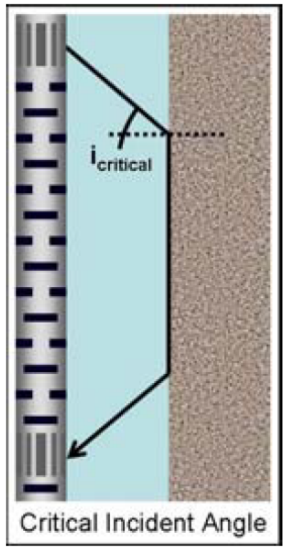


Figure 23 illustrates compressional wave velocity through example formations and the respective angles (icritical) required for critical refraction of compressional waves. The data assume that the borehole is filled with fresh water-based mud.

Figure 23. Compressional wave (P-wave) velocities and critical angles for example formations.

Formation	$V_{p\text{-}wave}$ (ft/sec)	Icritical
Dolomite (at 0% porosity)	22989	13.3
Limestone(at 0% porosity)	21008	14.6
Quartz sandstone (at 0% porosity)	18018	17.1
Consolidated shale	14285	21.7
Unconsolidated shale	7143	47.8
Assumed drilling fluid	$V_{mud\ wave}$ (ft/sec)	
Fresh water-based mud	5291	

From Figure 23, it is obvious that the incident angle required for critical refraction of compressional waves increases in formations with slower compressional wave velocities. However, in all example formations listed, the ratio Vbh/Vfm is less than 1.0, and the resulting angle icritical is some finite number. This indicates that critical refraction of compressional waves will occur in all cases.

Figure 24 similarly illustrates the fastest possible shear wave velocities (at 70% of compressional velocity) through the same formations, and the respective angles (icritical) required for critical refraction of shear waves. The borehole fluid is assumed to be fresh water-based mud.

Figure 24. Shear wave (S-wave) velocities and critical angles for example formations.

Formation	$V_{s\text{-wave}}$ (ft/sec)	Icritical
Dolomite (at 0% porosity)	16420	18.8
Limestone(at 0% porosity)	15006	20.6
Quartz sandstone (at 0% porosity)	12870	24.3
Consolidated shale	10204	31.2
Unconsolidated shale	5102	undifined
Assumed drilling fluid	$V_{mud\ wave}$ (ft/sec)	
Fresh water-based mud	5291	

From Figure 24, it is apparent that the incident angle required for critical refraction of shear waves also increases in formations with slower shear wave velocities. In very slow formations, the requirement that Vbh/Vfm be less than 1.0 is not met, and the incident angle required for critical refraction is undefined according to Snell's law. This means that, in formations where shear velocity is slower than the velocity of the fluid pressure wave through the borehole, critically refracted shear waves do not exist.

Monopole acoustic transmitters fail to generate critically refracted shear waves in formations where shear velocity is slower than that of the fluid pressure wave through the borehole. Such formations include unconsolidated shale, high-porosity shaly sandstone, coal, and diatomite. These formations are collectively known as slow formations because their acoustic velocities are slow in comparison to other rocks.

If shear wave velocity is necessary for rock properties applications in slow formations, then a dipole acoustic tool is required. Dipole acoustic transmitters generate a directional pulse and create a flexural wave that travels up and down the borehole wall. This flexural wave—at low frequencies—travels at the same velocity as would a critically refracted shear wave. Therefore, dipole acoustic tools are capable of acquiring shear velocity information through any type of formation.

Surface Waves

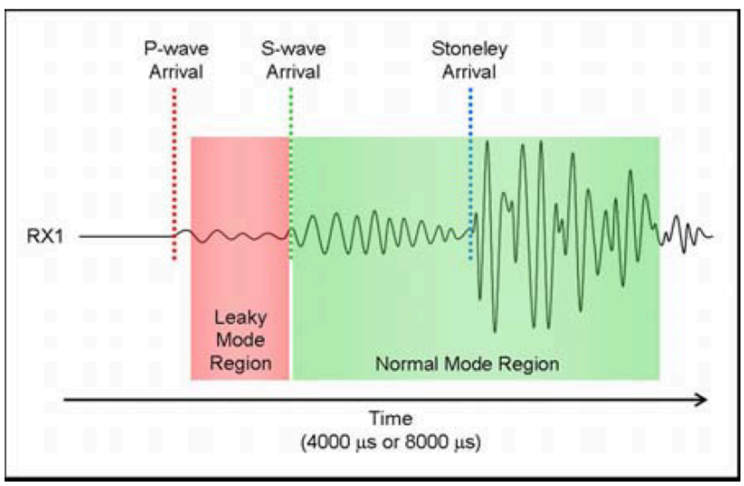
Surface waves are those which, as their name implies, travel along some surface. In this case, that "surface" is represented by the borehole wall. Fluid pressure waves generated by repetitive transmitter pulsing cause minute deformations of the borehole wall that travel up and down the borehole as surface waves. While the velocities of these surface waves are typically unimportant, the frequency of one particular type can be used to estimate permeability variations versus depth. Surface waves include:

- Leaky mode and normal mode waves
- Stoneley waves

Leaky and Normal Mode Waves

Leaky mode and normal mode (Fig. 25) are surface waves created at the borehole wall by interference between fluid pressure waves and critically refracted body waves. Leaky mode results from constructive interference between reflected fluid pressure waves and critically refracted Pwaves. Normal mode (also called pseudo-Rayleigh waves) result from constructive interference between reflected fluid pressure waves and critically refracted S-waves. Both leaky mode and normal node energy is propagated up and down the borehole wall as surface waves. However, because the creation of these waves involves energy reflected back into the borehole, their characteristics cannot be used to determine formation properties, and are unimportant.

Figure 25. Leaky mode and normal mode waves are unimportant for formation evaluation purposes.

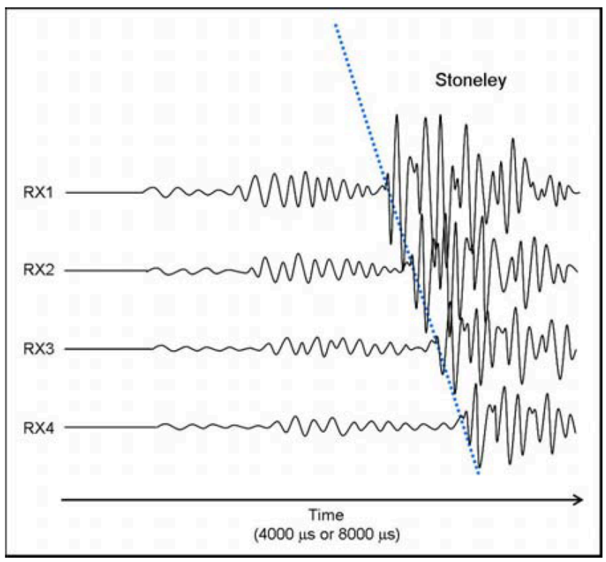


Stoneley Waves

Stoneley waves are surface waves created by the flexing of the interface between the borehole fluid and formation fluid with repetitive transmitter pulses. Each transmitter pulse causes a pressure increase on all sides of the tool which results in minute displacements of the borehole interface. Immediately following a transmitter pulse there is a sudden decrease in pressure and the fluid interface “rebounds.” This flexing of the fluid interface propagates up and down the borehole as a Stoneley wave.

Stoneley wave velocity depends upon a number of factors, some of which are characteristic of the logging tool and others of the borehole environment. Therefore, Stoneley wave velocity is not important for the purpose of formation evaluation. Stoneley waves appear as high amplitude arrivals on waveforms (Fig. 26), and occur much later in time than P-wave and S-wave arrivals. Because of their slow velocities, Stoneley wave arrivals typically coincide with much lower amplitude mud wave arrivals.

Figure 26. Stoneley arrivals are detected by a receiver much later in time.



The ability of pore fluids to be displaced away from the borehole wall by Stoneley flexing depends upon the interconnectivity of pores those fluids occupy. Permeability can be assumed to be proportional to the amount of interconnected pore space in a formation. The frequency of Stoneley waves, which depends upon the magnitude of fluid displacement at the borehole wall, can therefore be used to indicate permeability variations across formations with respect to depth. Fluid displacement by Stoneley flexing in low-permeability formations is minimal because, without a significant amount of interconnected pore space, fluids cannot be forced very far from the borehole wall. The rebounding of pore fluids through small and constricted pore throats results in high frequency Stoneley waves. In formations with higher permeability, Stoneley flexing is capable of forcing pore fluids a greater distance from the borehole wall because of the greater degree of pore interconnectivity. The rebounding of pore fluids through larger, more interconnected pore throats results in low-frequency Stoneley waves.

While such measurements of Stoneley frequency cannot provide a quantitative measure of permeability, they can be used to provide qualitative indications of permeability variations versus depth. Apart from the importance of frequency, Stoneley amplitude can be used in conjunction with the amplitudes of body waves (compressional and shear) to identify naturally fractured formations.

Delta-t

Delta-t (or interval transit time) refers to the time required for a critically refracted acoustic wave to transit one foot of formation. Compressional delta-t (ΔtC) is measured by determining the time differences between P-wave first arrivals at two receivers spaced a known distance apart.

$$\Delta t_C = \frac{1{,}000{,}000}{V_P}$$

Where: Δt_C = compressional delta-t (microseconds/foot)
V_P = P-wave velocity (feet/second)

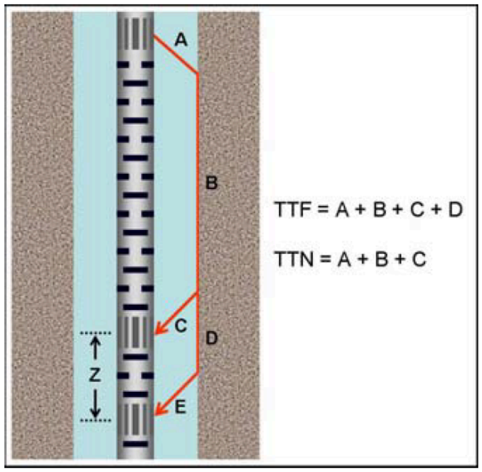
The faster the P-wave velocity, the less time required for it to transit the interval of formation between receivers. By industry standard, acoustic logs present velocity information in terms of delta-t (Δt) simply because its values are smaller and easier to manage than values of velocity. Figure 27 illustrates P-wave velocities and corresponding compressional delta-t (ΔtC) values for example formations and different types of borehole fluids. Note that the slower the velocity, the higher the value of delta-t. Similarly, as a formation's porosity increases, its compressional delta-t also increases.

Formation	$V_{p\text{-}wave}$ (ft/sec)	ΔT_c(μsec/ft)
Dolomite (at 0% porosity)	22989	43.5
Limestone(at 0% porosity)	21008	47.6
Quartz sandstone (at 0% porosity)	18018	55.5
Consolidated shale	14285	70
Unconsolidated shale	7143	140
Assumed drilling fluid	$V_{mud\ wave}$ (ft/sec)	ΔT_c(μsec/ft)
Fresh water-based mud	5291	189
Saltwater-based mud	5405	185
Oil-based-mud	4878	205

The Borehole Problem

Because compressional energy travels through the borehole as well as the formation in its journey from transmitter to receiver, the borehole poses potential problems in the computation of delta-t and requires compensation. Delta-t is computed from the travel times of a critically refracted P-wave to two receivers (near and far) spaced a known distance apart (Fig. 28). These travel times can be depicted as individual components through the formation and the borehole.

Figure 28. Travel time components through the borehole and formation.



Delta-t can be expressed in terms of these component travel times as follows

$$\Delta t = \frac{TTF - TTN}{Z} = \frac{(A+B+D+E)-(A+B+C)}{Z}$$

Where: E = C

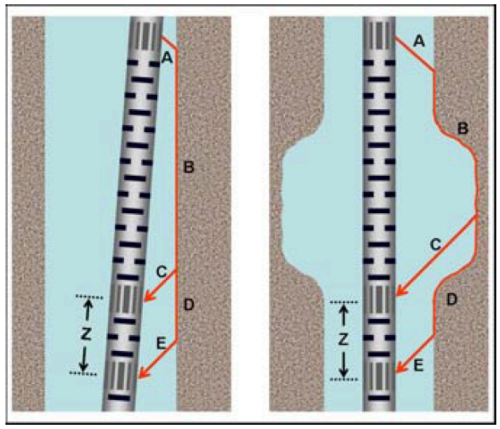
Provided that the toolstring is aligned parallel with the borehole axis and there are no washouts (as shown in Fig. 34), all travel times through the borehole fluid are equal (A = C = E). In this case, the computed delta-t is accurate, and determined as follows:

$$\Delta t = \frac{(A+B+D+E)-(A+B+C)}{Z} = \frac{D}{Z}$$

Where: E = C

Non-centralized toolstrings and the presence of washouts (Fig. 29) result in conditions where travel times through the borehole fluid are not equal (A ≠ C ≠ E). In these conditions, the computed delta-t is not accurate and requires compensation.

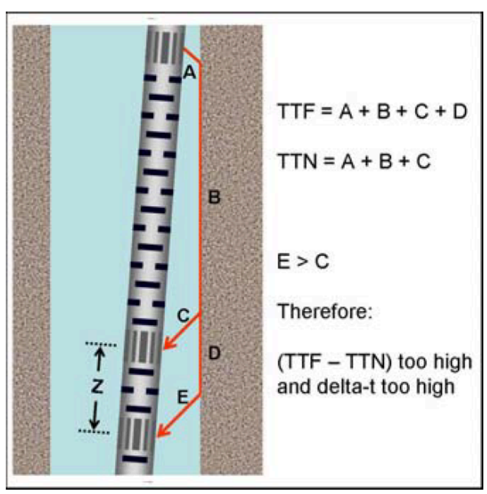
Figure 29. Non-centralized toolstrings and washouts require compensation of the delta-t value.



Tool Tilt

If the toolstring is not parallel to the borehole axis (tool tilt), then travel times of the fluid pressure wave from formation to both receivers are not equal (E ≠ C). In Figure 30, the toolstring is tilted so that the transmitter is closer to the borehole wall than both receivers.

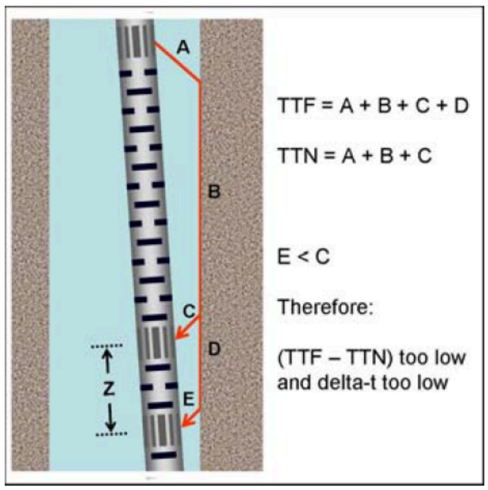
Figure 30. Travel time components for a tilted toolstring.



The fluid pressure wave travels a greater distance from formation to the far receiver (E) than from formation to the near receiver (C). Because delta-t is computed from the difference between near and far travel times (TTF – TTN), the extra time traveled from formation to the far receiver results in an optimistic delta-t value (too high).

If the toolstring is tilted so that the receivers are closer to the borehole wall than the transmitter (Fig. 31), then the opposite situation results. The fluid pressure wave travels a greater distance from formation to the near receiver (C) than from formation to the far receiver (E).

Figure 31. Travel time components for a tilted toolstring.

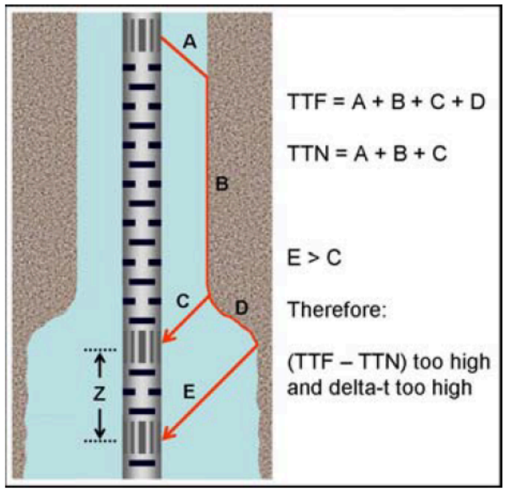


Delta-t computed from the difference between far and near travel times (TTF – TTN) is pessimistic (too low) because of the extra time traveled from formation to the near receiver.

Washout

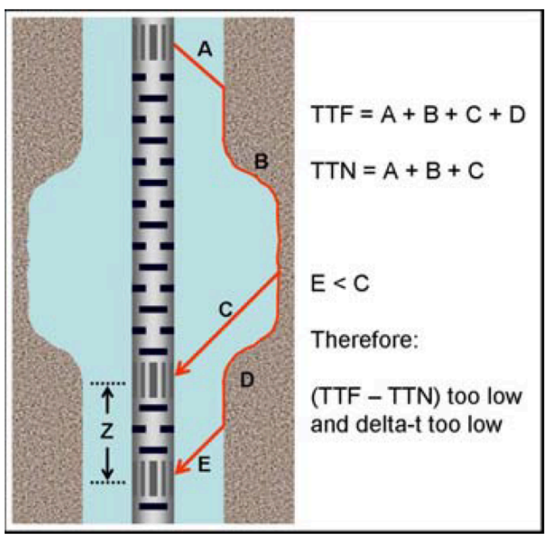
Washouts create similar problems because the fluid pressure wave travel time from formation to the near receiver may not equal its travel time from formation to the far receiver (E ≠ C). In Figure 32, travel time from formation to the far receiver (E) is greater than its travel time from formation to the near receiver (C), resulting in an optimistic delta-t (too high).

Figure 32. Travel time components in a washout.



Depending upon the location of the receivers with respect to the washout, the opposite may occur. In Figure 33, travel time of the fluid pressure wave from formation to the near receiver (C) is greater than its travel time from formation to the far receiver (E), resulting in a pessimistic delta-t (too low).

Figure 33. Travel time components in a washout.



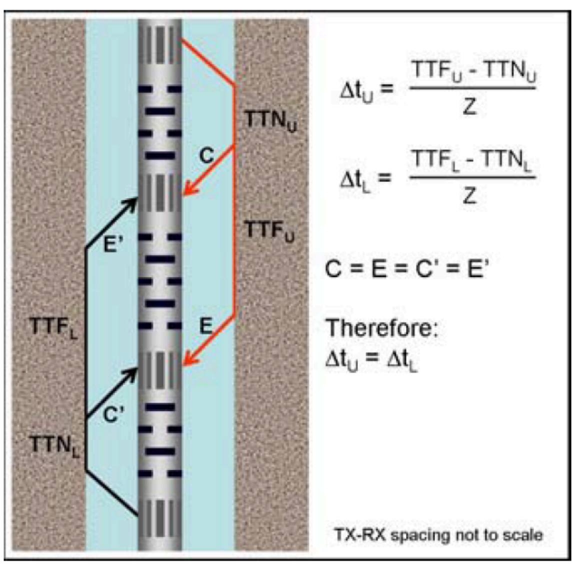
Delta-t computed from near and far travel times is only correct when the travel time through the borehole from formation to receiver is equal for both receivers (E = C). Delta-t will not be correct when the toolstring is tilted because of a lack of centralization, or when washouts are present. In these instances, travel times through the borehole from formation to both receivers will be different, resulting in a delta-t value that is either optimistic or pessimistic.

Borehole Compensation

A Borehole Compensated Dual Transmitter (BCDT) is designed with vertically opposed transmitter-receiver sets to acquire two measures of delta-t for every station point in the borehole. Tool tilt and washouts will both have equal but opposite effects on these two measures. Where these conditions cause one delta-t to be optimistic, they cause the other to be pessimistic, and vice versa. By taking the mathematic average of the two delta-t measures, tool tilt and washout effects are compensated and a more accurate delta-t is obtained.

At any station point, the BCDT measures near and far travel times for both the upper and lower transmitter-receiver sets. Two values of delta-t are computed: ΔtU and ΔtL. If the toolstring is aligned parallel to the borehole axis and there are no washouts (E = C), then either of these two measures provides an accurate value of delta-t. The average of these two measures, therefore, would also be accurate. This condition is illustrated in Figure 34.

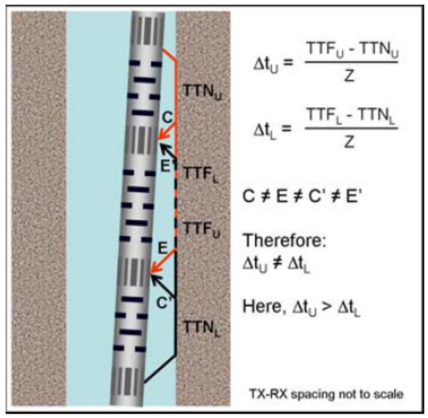
Figure 34. BCDT travel time components in perfect borehole conditions.



When the BCDT is not aligned parallel to the borehole axis because of poor centralization (Fig. 35), travel times through the borehole from formation to both receivers are no longer equal (E ≠ C ≠ E′ ≠ C′). In this case, as illustrated below, tool tilt will have equal but opposite effects on ΔtU and ΔtL.

Delta-t for the upper transmitter-receiver set (ΔtU) will be optimistic, while delta-t for the lower transmitter-receiver set (ΔtL) will be pessimistic.

Figure 35. BCDT travel time components in tilted-tool conditions.

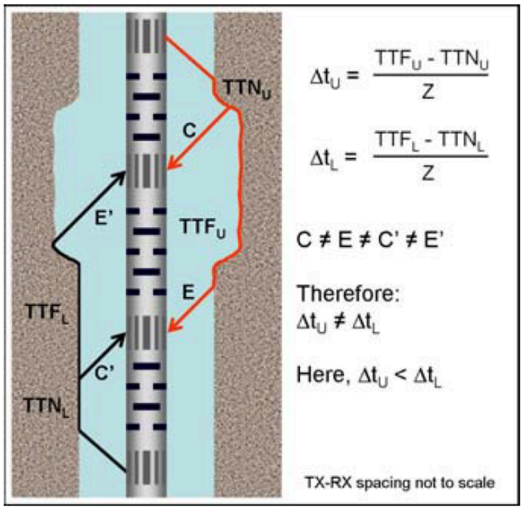


By taking the average of upper and lower delta-t values, the effect of tool tilt is compensated, and an accurate delta-t is obtained from the following equation:

$$\Delta t_{compensated} = \frac{1}{2}\left(\Delta t_U + \Delta t_L\right)$$

Where washouts are present (Fig. 36), travel times through the borehole from formation to both receivers are not equal (E ≠ C ≠ E′ ≠ C′). Washouts will similarly have equal but opposite effects of ΔtU and ΔtL; one will be optimistic while the other is pessimistic, or vice versa.

Figure 36. BCDT travel time components in washouts.



The BCDT service similarly compensates for washout by taking the average of the two delta-t values, obtaining an accurate measure of delta-t from the following equation:

$$\Delta t_{compensated} = \frac{1}{2}\left(\Delta t_U + \Delta t_L\right)$$

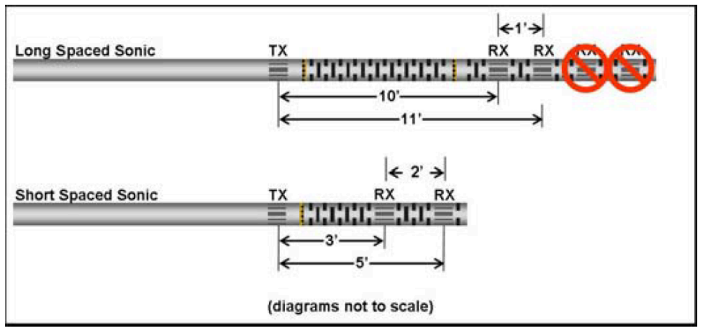
Borehole compensation of the BCDT service using vertically opposed transmitter-receiver sets provides a measure of delta-t that is compensated for both tool tilt (non-parallel alignment with the borehole axis) and for the presence of washouts.

Depth-Derived Borehole Compensation

The Long Spaced Sonic (LSS) and Short Spaced Sonic (SSS) services also compensate for borehole effects by averaging two delta-t values. However, because these tools employ only a single transmitter, the travel times used to compute these two delta-t values cannot be acquired at the same station point as with the BCDT. The LSS and SSS toolstrings must be moved vertically to compute a compensated delta-t. This particular method of compensation is called depth-derived borehole compensation.

Both the LSS and SSS utilize a transmitter and a set of two receivers positioned below the transmitter at different offsets and with different receiver spacings (Fig. 37).

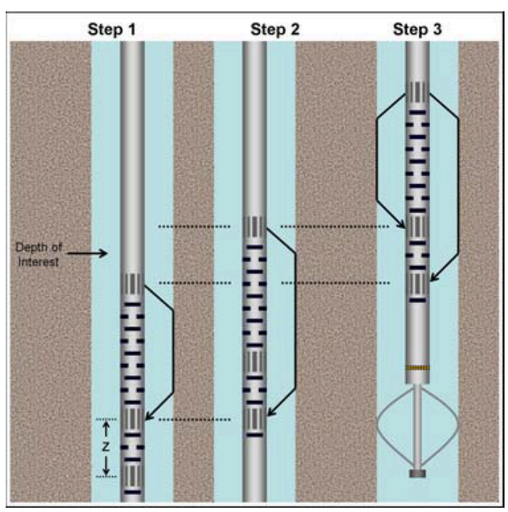
Figure 37. Offsets and spacings of the LSS and SSS toolstrings.



The concept of depth-derived borehole compensation is very similar to the compensation routine of the dual-transmitter BCDT. Depth-derived borehole compensation (Fig. 38) is a three-step process that involves acquiring travel time measurements at three different station points in the borehole. From these travel time measurements, two delta-t values (ΔtTX and ΔtRX) are computed and averaged

to compensate for the effects of washout.

Figure 38. Depth-derived borehole compensation is a three-step process.



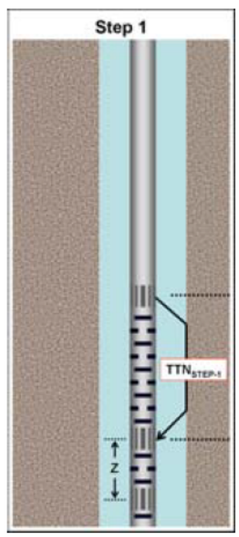
Delta-t transmitter (ΔtTX) is computed from travel times acquired during the first two steps while the toolstring is positioned so that transmitter station points straddle the depth of interest. The toolstring is then moved farther uphole, and a value of delta-t receiver (ΔtRX) is computed from travel times acquired during the third step while receiver station points straddle the same depth of interest.

Depth-derived borehole compensation is best explained by considering each of the three steps individually.

Step 1

Beginning with the toolstring positioned at any station point in the borehole, travel times between transmitter and both near and far receivers are measured as usual (Fig. 39). The travel time acquired between transmitter and the near receiver (ΔtStep-1) will be used to compute ΔtTX (delta-t transmitter).

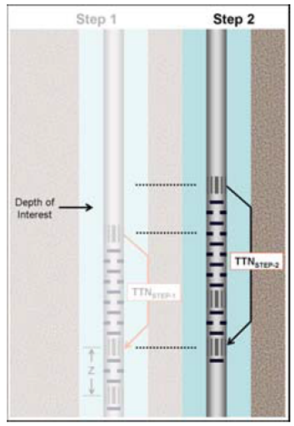
Figure 39. Step 1 of the depth-derived borehole compensation routine.



Step 2

As the toolstring is continually moved uphole, it will ultimately reach a station point at which the far receiver is positioned at exactly the same depth as the near receiver was during Step 1 (Fig. 40). The distance required for the toolstring to reach this second station point is one receiver spacing (1- foot for LSS, 2-feet for SSS).

Figure 40. Step 2 of the depth-derived borehole compensation routine.



The travel time acquired between transmitter and the far receiver (TTFStep-2) is measured, and delta-t transmitter (ΔtTX) is computed from the following equation:

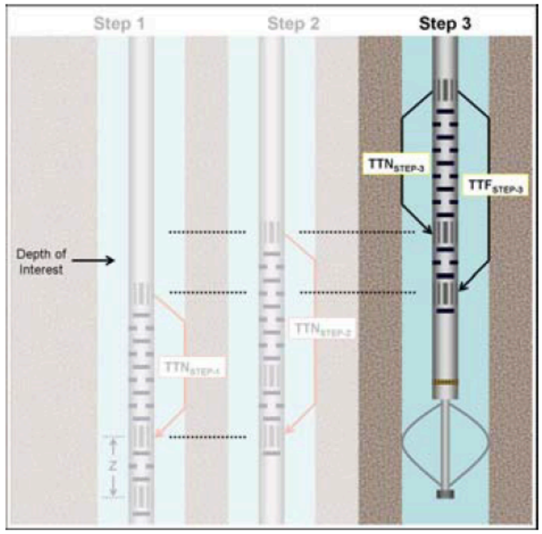
$$\Delta t_{TX} = \frac{TTF_{Step-2} - TTN_{Step-1}}{Z}$$

As with any delta-t measurement, ΔtTX may either be optimistic or pessimistic, depending upon tool position and the presence of washouts.

Step 3

With continued vertical motion of the toolstring, it ultimately reaches a station point at which the two receivers are positioned at exactly the same depths as transmitter station points during Step 1 and Step 2 (Fig. 41). The distance required for the toolstring to reach this third station point is one offset (10-feet for LSS, 3-feet for SSS).

Figure 41. Step 3 of the depth-derived borehole compensation routine.



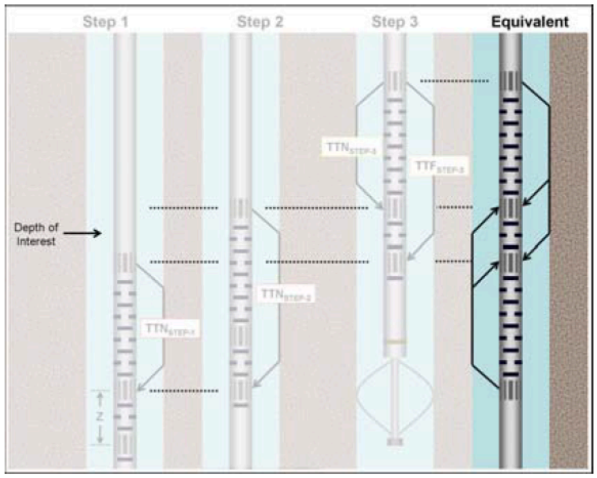
Travel times between transmitter and both near and far receivers are measured at this third station point, and delta-t receiver (ΔtRX) is computed from the following equation:

$$\Delta t_{RX} = \frac{TTF_{Step-3} - TTN_{Step-3}}{Z}$$

As before, ΔtRX may be either optimistic or pessimistic, depending upon tool position and the presence of washouts. However, borehole effects on ΔtRX will be equal but opposite the effects on ΔtTX computed from travel times acquired in Step 1 and Step 2.

Though depth-derived borehole compensation may seem complex, its concept is identical to having a dual-transmitter toolstring with vertically opposed transmitter-receiver sets positioned so that the two receivers straddle the depth of interest. In this sense, depth-derived borehole compensation is very similar to the compensation routine used by the BCDT.

Figure 42. The concept of depth-derived borehole compensation is very similar to borehole compensation of the BCDT.



Washouts have equal but opposite effects on delta-t transmitter (ΔtTX) and delta-t receiver (ΔtRX). Therefore, a compensated delta-t measurement can be obtained by taking their mathematic average by the following equation:

$$\Delta t_{compensated} = \frac{1}{2}\left(\Delta t_{TX} + \Delta t_{RX}\right)$$

Unlike the BCDT, depth-derived borehole compensation requires that the toolstring be moved to acquire travel time measurements at the three station points. Because of this, the LSS and SSS toolstrings must be centralized (Fig. 43) in order to minimize any differences in travel time through the borehole resulting from the toolstring not being aligned parallel to the borehole axis (tool tilt).

Figure 43. Overbody centralizer installed on a Short Spaced Sonic Tool.

Depth-derived borehole compensation only compensates for washout. It cannot compensate for tool tilt. Proper centralization is a must.