16. THE SONIC OR ACOUSTIC LOG

16.1 Introduction

The *sonic* or *acoustic* log measures the travel time of an elastic wave through the formation. This information can also be used to derive the velocity of elastic waves through the formation.

Its main use is to provide information to support and calibrate seismic data and to derive the porosity of a formation.

The main uses are:

- Provision of a record of "seismic" velocity and travel time throughout a borehole. This information can be used to calibrate a seismic data set (i.e., tie it in to measured values of seismic velocity).
- Provision of "seismic" data for the use in creating synthetic seismograms.
- Determination of porosity (together with the FDC and CNL tools).
- Stratigraphic correlation.
- Identification of lithologies.
- Facies recognition.
- Fracture identification.
- Identification of compaction.
- Identification of over-pressures.
- Identification of source rocks.

The tool works at a higher frequency than seismic waves, therefore one must be careful with the direct comparison and application of sonic log data with seismic data.

16.2 Theory

16.2.1 Wave Types

The tool measures the time it takes for a pulse of "sound" (i.e., and *elastic wave*) to travel from a transmitter to a receiver, which are both mounted on the tool. The transmitted pulse is very short and of high amplitude. This travels through the rock in various different forms while undergoing *dispersion* (spreading of the wave energy in time and space) and *attenuation* (loss of energy through absorption of energy by the formations).

When the sound energy arrives at the receiver, having passed through the rock, it does so at different times in the form of different types of wave. This is because the different types of wave travel with different velocities in the rock or take different pathways to the receiver. Figure 16.1 shows a typical received train of waves. The transmitter fires at $t = 0$. It is not shown in the figure because it is masked from the received information by switching the receiver off for the short duration during which the pulse is transmitted. This is done to ensure that the received information is not too complicated, and to protect the sensitive receiver from the high amplitude pulse. After some time the first type of wave arrives. This is the *compressional* or *longitudinal* or *pressure* wave (*P-wave*). It is usually the fastest wave, and has a small amplitude. The next wave, usually, to arrive is the *transverse* or *shear* wave (*S-*

wave). This is slower than the P-wave, but usually has a higher amplitude. The shear wave cannot propagate in fluids, as fluids do not behave elastically under shear deformation. These are the most important two waves. After them come *Rayleigh waves*, *Stoneley waves*, and *mud waves*. The first two of these waves are associated with energy moving along the borehole wall, and the last is a pressure wave that travels through the mud in the borehole. They can be high amplitude, but always arrive after the main waves have arrived and are usually masked out of the data. There may also be unwanted P-waves and S-waves that travel through the body of the tool, but these are minimized by good tool design by (i) reducing their received amplitude by arranging damping along the tool, and (ii) delaying their arrival until the P-wave and S-wave have arrived by ensuring that the pathway along the tool is a long and complex one.

The data of interest is the time taken for the P-wave to travel from the transmitter to the receiver. This is measured by circuitry that starts timing at the pulse transmission and has a threshold on the receiver. When the first P-wave arrival appears the threshold is exceeded and the timer stops. Clearly the threshold needs to be high enough so that random noise in the signal dies not trigger the circuit, but low enough to ensure that the P-wave arrival is accurately timed.

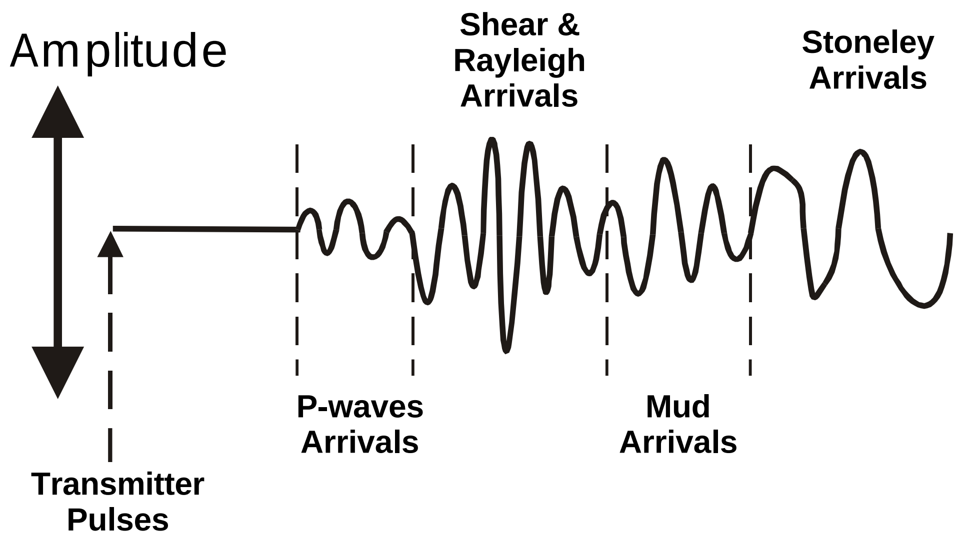


Fig. 16.1 The geophysical wavetrain received by a sonic log.

There are complex tools that make use of both P-waves and S-waves, and some that record the full wave train (*full waveform logs*). However, for the simple sonic log that we are interested in, only the *first arrival* of the P-wave is of interest. The time between the transmission of the pulse and the reception of the first arrival P-wave is the one-way time between the transmitter and the receiver. If one knows the distance between the transmitter (Tx) and the receiver (Rx), the velocity of the wave in the formation opposite to the tool can be found.

In practice the sonic log data is not presented as a travel time, because different tools have different Tx-Rx spacings, so there would be an ambiguity. Nor is the data presented as a velocity. The data is presented as a *slowness* or the travel time per foot traveled through the formation, which is called delta t (Δt or ΔT), and is usually measured in μs/ft. Hence we can write a conversion equation between velocity and slowness:

$$\Delta t = \frac{10^6}{V} \qquad \textbf{(16.1)}$$

where the slowness, Δt is in microseconds per foot, and the velocity, V is in feet per second.

The velocity of the compressional wave depends upon the elastic properties of the rock (matrix plus fluid), so the measured slowness varies depending upon the composition and microstructure of the matrix, the type and distribution of the pore fluid and the porosity of the rock. The velocity of a P-wave in a material is directly proportional to the strength of the material and inversely proportional to the density of the material. Hence, the slowness of a P-wave in a material is inversely proportional to the strength of the material and directly proportional to the density of the material, i.e.;

$$V \propto \frac{\text{Strength}}{r} \quad \text{and} \quad \Delta t \propto \frac{r}{\text{Strength}} \qquad \textbf{(16.2)}$$

The strength of a material is defined by two parameters (i) the bulk modulus, and (ii) the shear modulus.

The bulk modulus, *K* is the extent to which a material can withstand isotropic squeezing (Fig. 16.2a). Imagine an amount of material subjected to an isotropic pressure P_1. Now let the isotropic pressure increase to a pressure P_2. The material will compress from its initial volume v_1 to a new smaller volume v_2. The bulk modulus is then given by;

$$K = \frac{P_2 - P_1}{(v_1 - v_2)/v_1} = \frac{\Delta P}{\Delta v / v_1} \qquad \textbf{(16.3)}$$

where ΔP is the change in pressure, and Δv is the change in volume. Thus ΔP is the change in pressure that causes Δv change in volume.

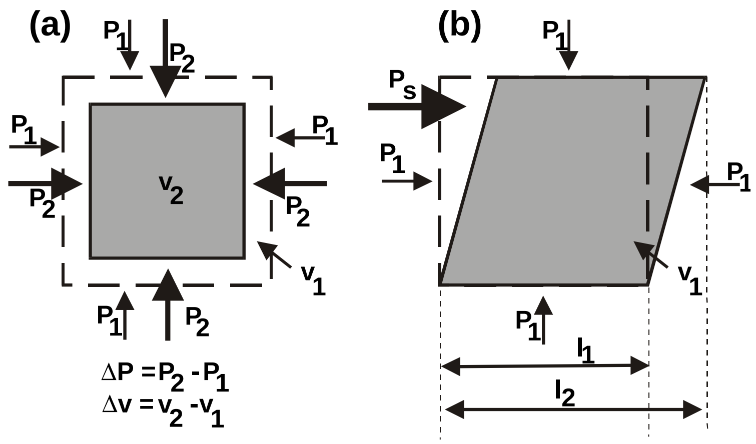


Fig. 16.2 The definition of bulk and shear moduli.

The shear modulus, m is the extent to which a material can withstand shearing (Fig. 16.2b). Imagine an amount of material subjected to a isotropic pressure P_1. Now apply a shear stress (non-isotropic pressure) P_s to one side of the sample. The material will shear to the new shape, and its overall length will increase from its initial length l_1 to a new larger length l_2. The bulk modulus is then given by;

$$m = \frac{P_s}{(l_2 - l_1)} = \frac{P_s}{g} \qquad \textbf{(16.4)}$$

where g is the shear strain. The application of the shear stress P_s causes the development of a shear strain g.

Detailed analysis of the velocity and slowness of P-waves in a material shows that;

$$V_P = \sqrt{\frac{K + \frac{4}{3}m}{r}} \quad \text{for solids} \qquad \textbf{(16.5)}$$

$$V_P = \sqrt{\frac{K}{r}} \quad \text{for fluids} \qquad \textbf{(16.6)}$$

16.2.2 Reflection and Refraction

The transmitter emits “sound” waves at a frequency of about 20-40 kHz, in short pulses, of which there are between 10 and 60 per second depending on the tool manufacturer. The energy spreads out in all directions.

Imagine a pulse emanating from a Tx on a sonic tool. It will travel through the drilling mud and encounter the wall of the borehole. The P-wave travels well through the mud at a relatively slow velocity, V_m, as the mud has a low density. The S-wave will not travel through liquid mud. At the interface it is both reflected back into the mud and refracted into the formation. The portion of the P-wave energy that is refracted into the formation travels at a higher velocity, V_f, because the density of the rock is higher. This is depicted in Fig. 16.3. We can use Snell’s law to write;

$$\frac{\sin i}{\sin R} = \frac{V_m}{V_f} \qquad \textbf{(16.7)}$$

and at the critical angle of refraction, where the refracted wave travels along the borehole wall, $R = 90^o$, so;

$$\sin i = \frac{V_m}{V_f} \qquad \textbf{(16.8)}$$

Hence, if the velocity of the elastic wave in the formation changes, the critical angle, i, will also change.

The velocity of the refracted wave along the borehole wall remains V_f. Each point reached by the wave acts as a new source retransmitting waves back into the borehole at velocity V_m.

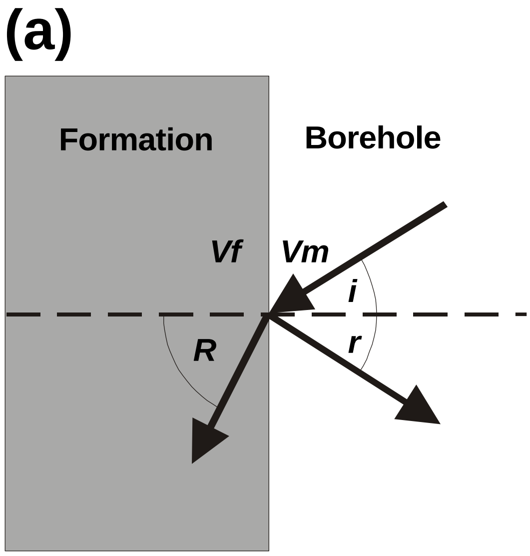


Fig. 16.3 Reflection and refraction at the borehole wall.

16.3 Sonic Tools

16.3.1 Early Tools

Early tools had one Tx and one Rx (Fig. 16.4). The body of the tool was made from rubber (low velocity and high attenuation material) to stop waves travelling preferentially down the tool to the Rx. There were two main problems with this tool. (i) The measured travel time was always too long because the time taken for the elastic waves to pass through the mud was included in the measurement. The measured time was A+B+C rather than just B. (ii) The length of the formation through which the elastic wave traveled (B) was not constant because changes to the velocity of the wave depending upon the formation altered the critical refraction angle.

16.3.2 Dual Receiver Tools

These tools were designed to overcome the problems in the early tools. They use two receivers a few feet apart, and measure the *difference* in times of arrival of elastic waves at each Rx from a given pulse from the Tx (Fig. 16.5). This time is called the *sonic interval transit time* (Δt) and is the time taken for the elastic wave to travel through the interval D (i.e., the distance between the receivers).

- The time taken for elastic wave to reach Rx1: T_{Rx1}= A+B+C
- The time taken for elastic wave to reach Rx2: T_{Rx2} = A+B+D+E
- The sonic interval transit time: $\Delta T = (T_{Rx2} - T_{Rx1})$ = A+B+D+E – (A+B+C) = D+E-C.
- If tool is axial in borehole: C = E, so $\Delta T = (T_{Rx2} - T_{Rx1})$ = D

The problem with this arrangement is that if the tool is tilted in the hole, or the hole size changes (Fig. 16.6), we can see that C ≠ E, and the two Rx system fails to work.

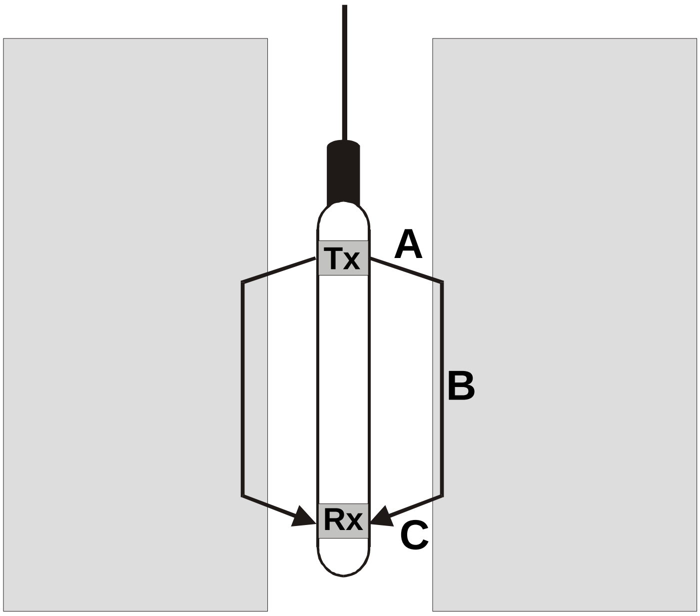


Fig. 16.4 Early sonic tools.

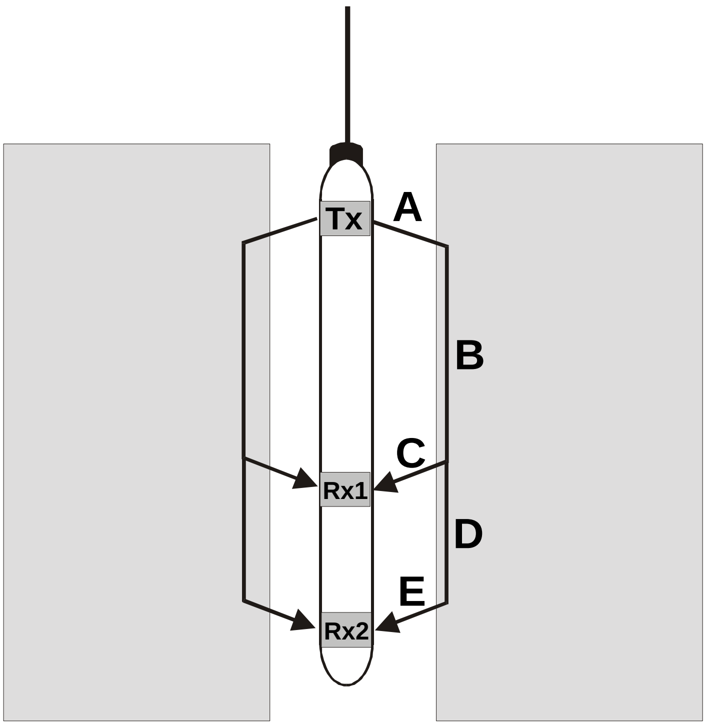


Fig. 16.5 Dual receiver sonic tools in correct configuration.

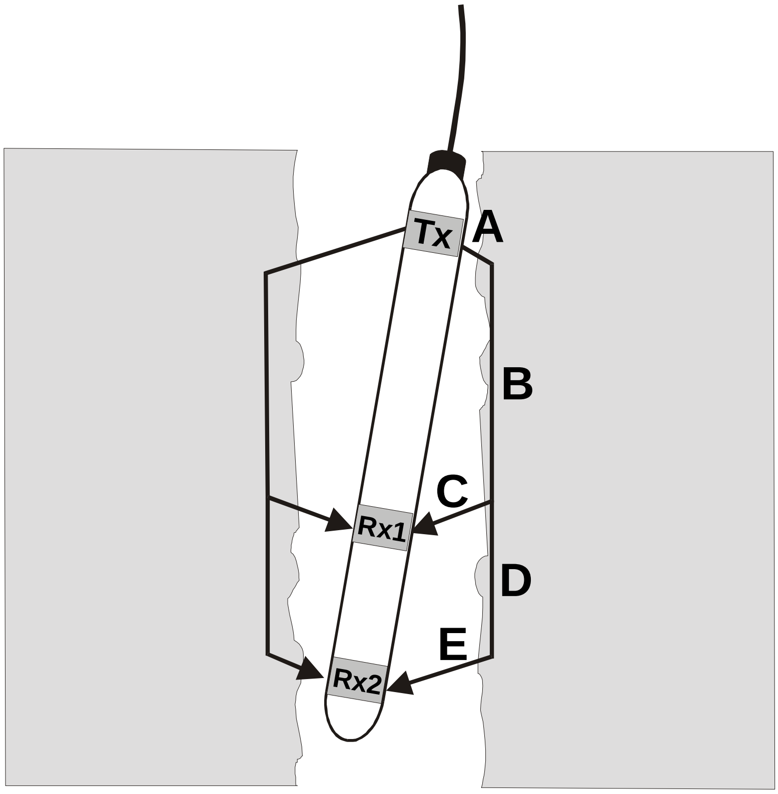


Fig. 16.6 Dual receiver sonic tools in incorrect configuration.

16.3.3 Borehole Compensated Sonic (BHC) Tool

This tool compensates automatically for problems with tool misalignment and the varying size of the hole (to some extent) that were encountered with the dual receiver tools. It has two transmitters and four receivers, arranged in two dual receiver sets, but with one set inverted (i.e., in the opposite direction). Each of the transmitters is pulsed alternately, and Δt values are measured from alternate pairs of receivers (Fig. 16.7). These two values of Δt are then averaged to compensate for tool misalignment, at to some extent for changes in the borehole size.

A typical pulse for the BHC is 100 μs to 200 μs, with a gap of about 50 ms, giving about 20 pulses per second. There are four individual Tx-Rx readings needed per measurement, so 5 measurements can be made per second. At a typical logging speed of 1500 m/h (5000 ft/h), gives one reading per 8 cm (3 inches) of borehole. Several versions of the BHC are available with different Tx-Rx distances (3 ft. and 5 ft. being typical), and the Rx-Rx distance between pairs of receivers is usually 2 ft.

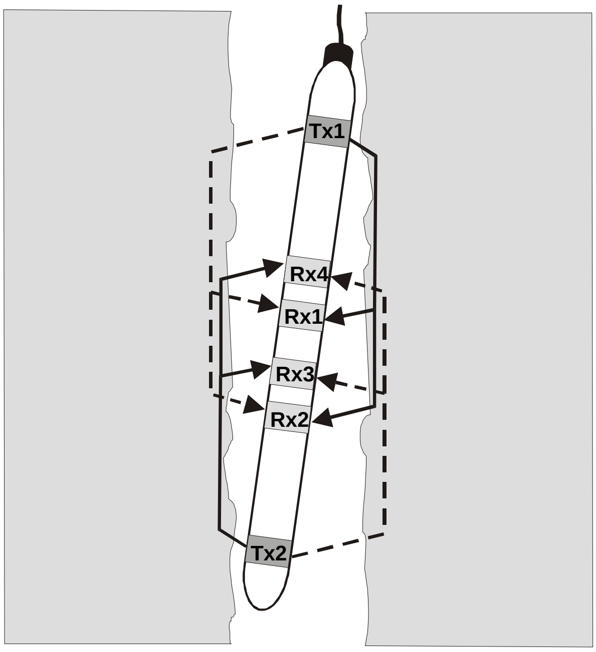


Fig. 16.7 Borehole compensated sonic tools.

16.3.4 Long Spacing Sonic (LSS) Tool

It was recognized that in some logging conditions a longer Tx-Rx distance could help. Hence Schlumberger developed the *long spacing sonic* (LSS), which has two Tx two feet apart, and two Tx also two feet apart but separated from the Tx by 8 feet. This tool gives two readings; a near reading with a 8-10 ft. spacing, and a far reading with a 10-12 ft. spacing (Fig. 16.8).

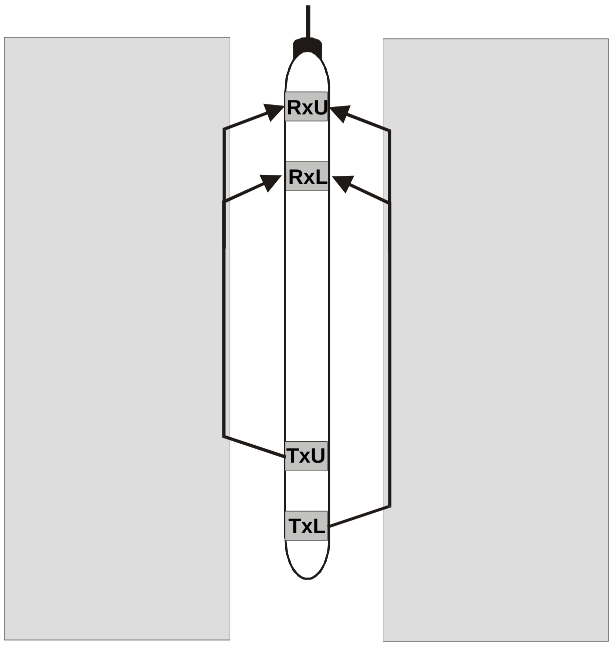


Fig. 16.8 Long spacing sonic tools.

16.3.5 Common Industry Tools

Table 16.1 shows the names and mnemonics of common industry sonic tools.

Table 16.1 The names and mnemonics of common industry sonic tools.

Tool	Mnemonic	Company
Compensated sonic sonde	CSS	BPB
Long spaced compensated sonic	LCS	
Borehole compensated sonde	BCS	Halliburton
Long spaced sonic	LSS	
Borehole compensated sonic	BHC	Schlumberger
Long spaced sonic	LSS	
Array sonic (standard mode)	DTCO	
Borehole compensated acoustilog	AC	Western Atlas
Long-spaced BHC acoustilog	ACL	

16.4 Calibration

The tool is calibrated inside the borehole opposite beds of pure and known lithology, such as anhydrite (50.0 μs/ft.), salt (66.7 μs/ft.), or inside the casing (57.1 μs/ft.).

16.5 Log Presentation

The interval transit time Δt is recorded on the log in microseconds per foot (μs/ft.). If the log is run on its own, the log takes up the whole of Track 2 and 3, if combined with other logs, it is usually put in Track 3 (Fig. 16.9). Most formations give transit times between 40 μs/ft. and 140 μs/ft., so these values are usually used as the scale.

The log will also show the *integrated travel time* (TTI). This value is derived simultaneously with the main measurement, and is the mean travel time in milliseconds. It is shown by pips on the right side of the depth column (in slightly different styles by different companies). The small pips occur every 1 millisecond and the larger ones occur every 10 milliseconds. The main advantage of this is that the average travel time between two depths can be found by simply counting the pips, which is really useful when comparing sonic logs to seismic sections. Likewise adding the pips together for a certain depth interval, and dividing by the thickness of the interval allows the mean velocity of the interval to be simply calculated. In the comparison it ***MUST*** be remembered that the pips give one-way travel time, and must be doubled to be compared to the two way travel time given in seismic data.

The accuracy of the travel time integrator can be checked on a log in a thick homogeneous formation. First, count the pips over the thickness of the interval to get the TTI value in milliseconds. Then read off the eyeballed mean Δt in the interval in microseconds per foot, multiply by the thickness of the interval and divide by 1000. The value should agree with the TTI reading.

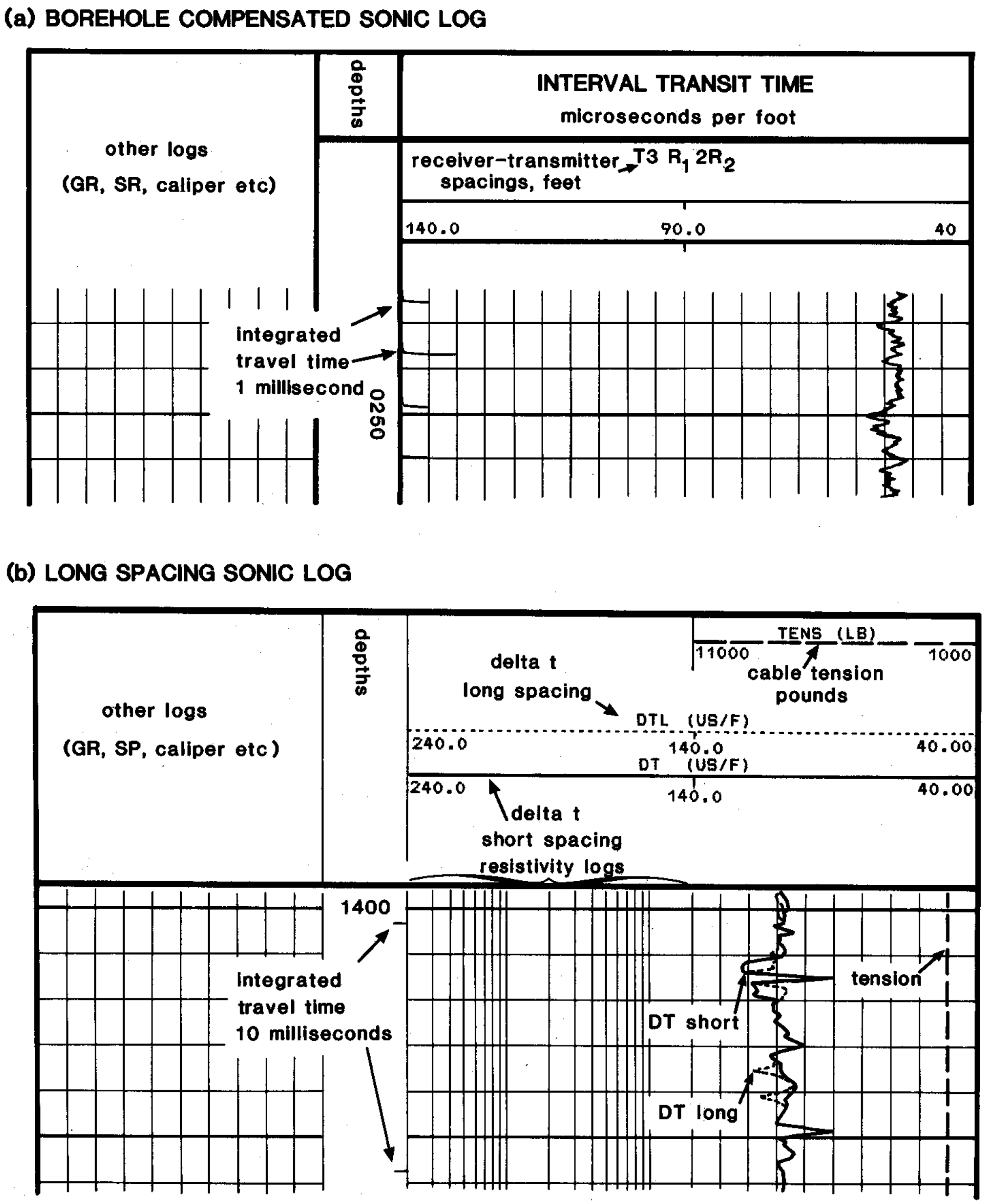


Fig. 16.9 Presentation of the sonic log. (a) BHC, (b) ISF-Sonic combination. (courtesy of Schlumberger and Rider)

16.6 Depth of Investigation

This is complex and will not be covered in great detail here. In theory, the refracted wave travels along the borehole wall, and hence the depth of penetration is small (2.5 to 25 cm). It is independent of Tx-Rx spacing, but depends upon the wavelength of the elastic wave, with larger wavelengths giving larger penetrations. As wavelength *l* = *V*/*f* (i.e., velocity divided by frequency), for any given tool frequency, the higher the velocity the formation has, the larger the wavelength and the deeper the penetration.

16.7 Vertical and Bed Resolution

The vertical resolution is equal to the Rx-Rx spacing, and hence is 2 ft. Beds less than this thickness can be observed, but will not have the signal fully developed. There are now some special tools which have an even better resolutions (e.g., ACL and DAC), but these are array sonic logs that will not be covered in this course.

16.8 Logging Speed

The typical logging speed for the tool is 5000 ft/hr (1500 m/hr), although it is occasionally run at lower speeds to increase the vertical resolution.

16.9 Logging Problems

16.9.1 Noise

Noise from stray electrical fields, the electronics package or derived from mechanically generated noise in rough holes can trigger the detection circuitry before the first arrival, causing a false (shorter) apparent first arrival. To limit this effect, all receiver circuits are disabled for 120 microseconds after the pulse. As the remaining time for the possibility of a noise spike occurring is greater for the far detector than the near one, most noise spikes occur for the far detector, which leads to values of Δt that are too small. These are seen as single data point spikes of low Δt in the log (Figs. 16.10 and 16.11).

16.9.2 **D*t* Stretch**

In heavily attenuating formations the value of Δt can be slightly too large due to the thresholding method employed by the detection circuitry. However, this problem is rarely significant, and is impossible to detect from the log.

16.9.3 **Cycle Skipping**

This is the occurrence of a failure in the thresholding to detect the first cycle of the wave's first arrival. Triggering may then occur at the second or even third cycle. This causes a marked and sudden shift to higher Δt values, followed by a shift back again to the correct value.

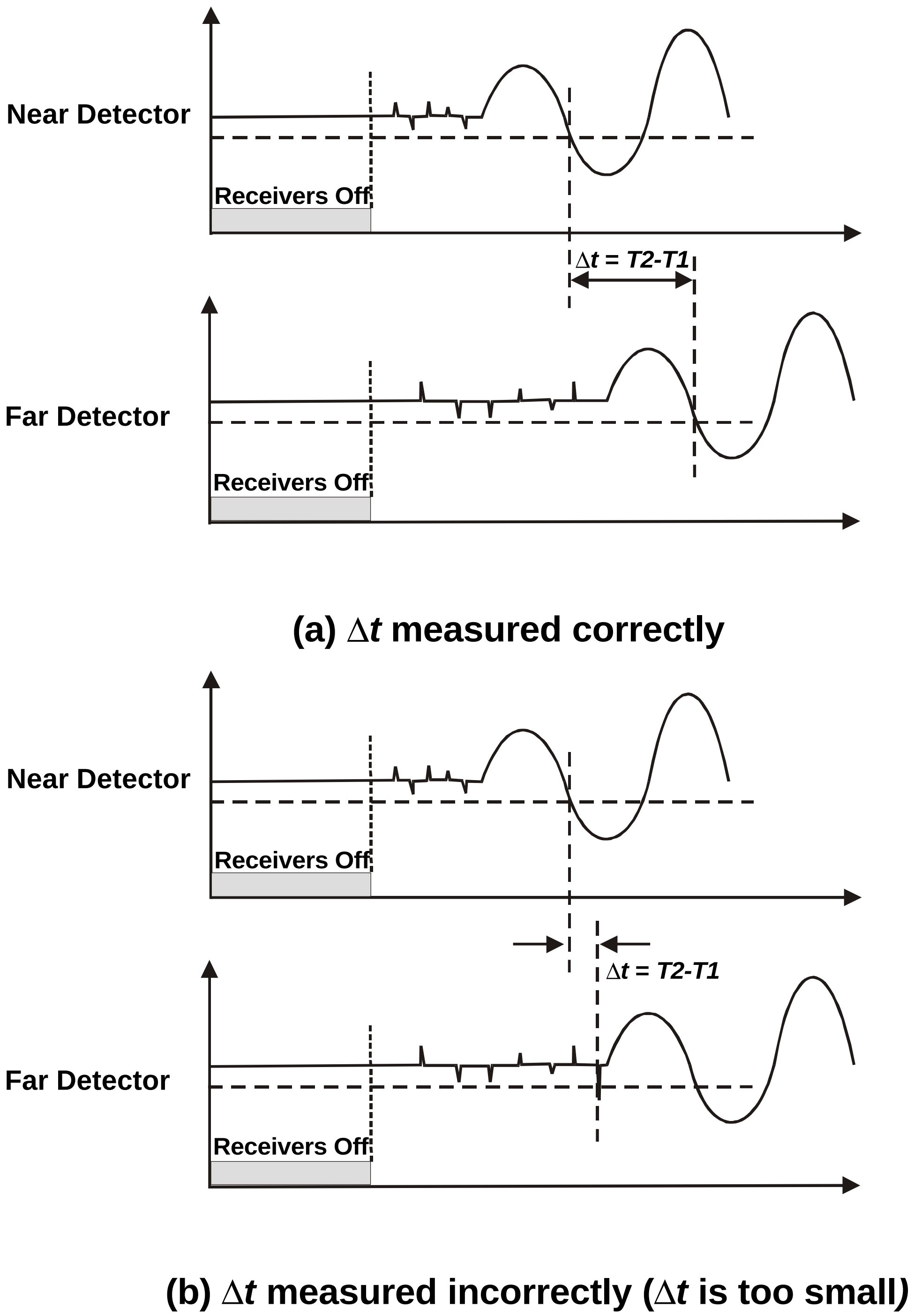


Fig. 16.10 The effect of noise spikes on thresholding.

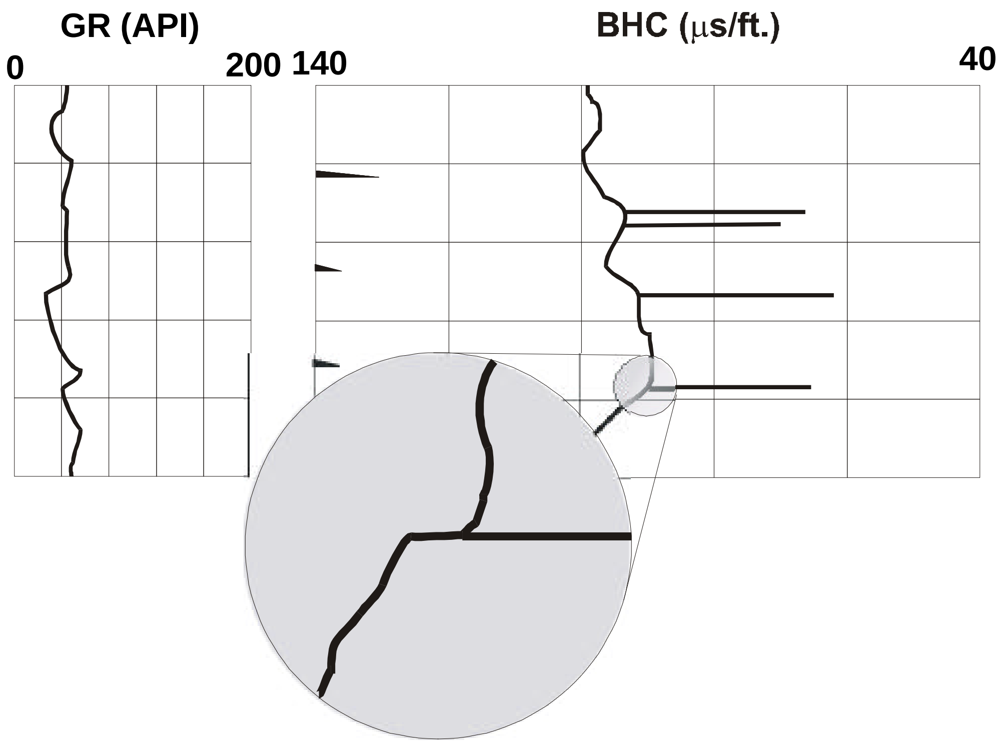


Fig. 16.11 How noise spikes occur in the log.

16.9.4 Mud Arrivals

Clearly the first arrival should be from a P-wave that has traveled through the formation. In some circumstances the P-wave that has traveled directly through the mud arrives first. This occurs if the Tx-Rx is smaller than a critical distance that depends upon the velocities of the P-wave through the formation and the mud, the diameter of the borehole and the diameter of the tool. Tools are designed to avoid this by making the Tx-Rx distance large enough for most applications. However, in some large diameter holes, the mud arrivals may come first. This leads to there being no structure in the sonic log response because the travel time through the mud is all that is being recorded. In these circumstances the tool may be run eccentred, but at the risk of picking up more noise spikes from the noise associated with the rough borehole surface.

16.9.5 Altered Zone Arrivals

The formation next to the borehole may not be typical of the rock. For example, it may be filled with solid mud and have a higher velocity than the virgin formation, or it may be fractured or altered and have a lower velocity. This is an analogous problem to the mud arrival problem.

If a low velocity altered zone exists, the Tx-Rx spacing must be large to ensure that the P-wave from the virgin formation arrives before that from the altered zone. In this case an LSS should provide better data than a BHC type log.

If a high velocity altered zone exists, there is no solution whatever type of log is used. The measured log value will be that for the altered zone.

A graph can be drawn to show the reliability of tools affected by mud and altered zone arrivals (Fig. 16.12). It is clear that the LSS has the better performance. However, the greater spacing means that arrival waves are weaker and therefore more prone to cycle skipping and noise spikes.

Figure 16.13 shows an example of altered zone arrivals affecting a BHC log but not an LSS log.

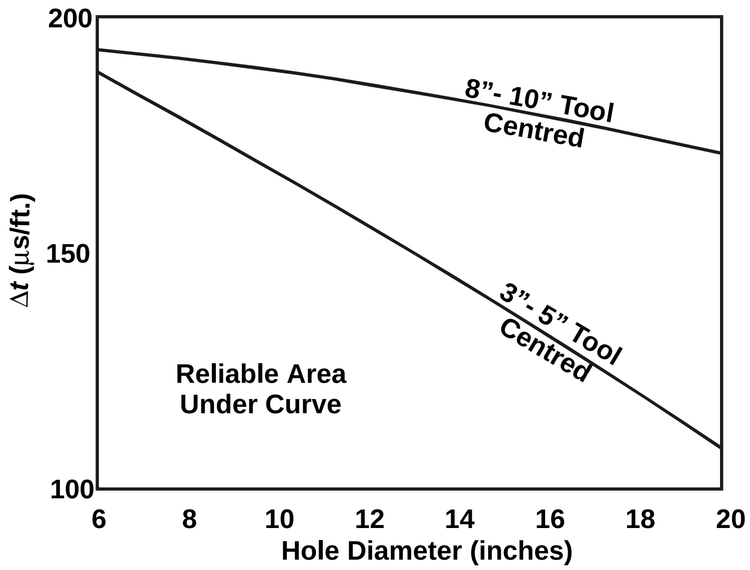


Fig. 16.12 Schematic reliability chart for Schlumberger tools (redrawn from Schlumberger data).

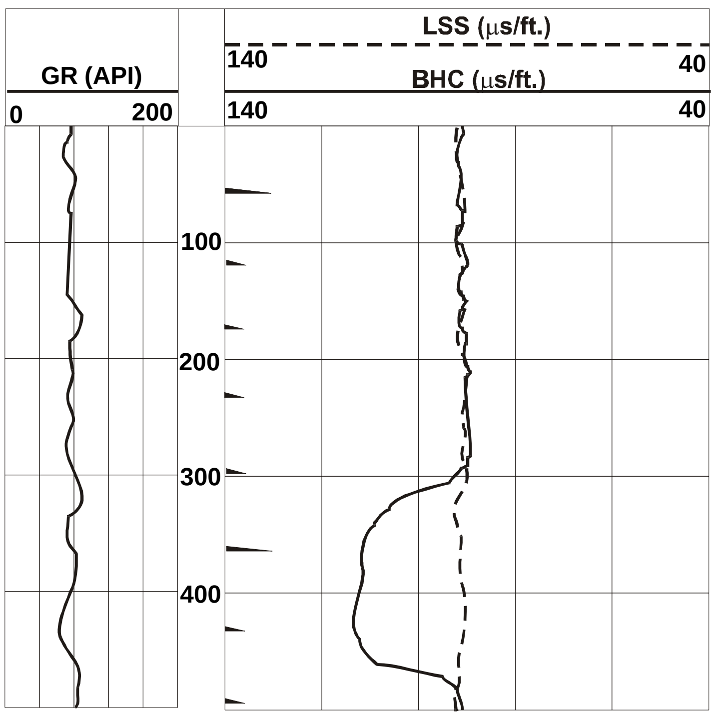


Fig. 16.13 Example of altered zone arrivals affecting the BHC log.

16.10 Uses of the Sonic Log

16.10.1 Seismic Data Calibration

The presence of a sonic log in a well that occurs on a seismic line or in a 3D survey enables the log data to be used to calibrate and check the seismic data. As the resolution of the sonic log is about 61 cm and that of the seismic technique is 10 m to 50 m, the sonic data must be averaged for the comparison to be made. However, the higher resolution of the sonic log may enable the log information to resolve indications of beds that are just beyond the resolution of the seismic technique.

It must be remembered that the sonic log gives a one-way travel time, and the seismic technique gives a two-way travel time.

16.10.2 Seismic Interval Velocities

The average sonic log interval velocity is obtained by counting the TTI pips over the interval concerned and dividing the thickness of the interval by this value.

A time-depth curve can then be obtained by taking a weighted sum of the interval velocities with depth, which will give the total time to a given depth and plotting this against depth. Figure 6.14 shows an example of such a curve, where the sonic interval transit time is given in parentheses next to the depth column.

The time-depth curve can then be compared against the velocity analyses from the seismic data, or can be used in place of velocity analyses in seismic processing.

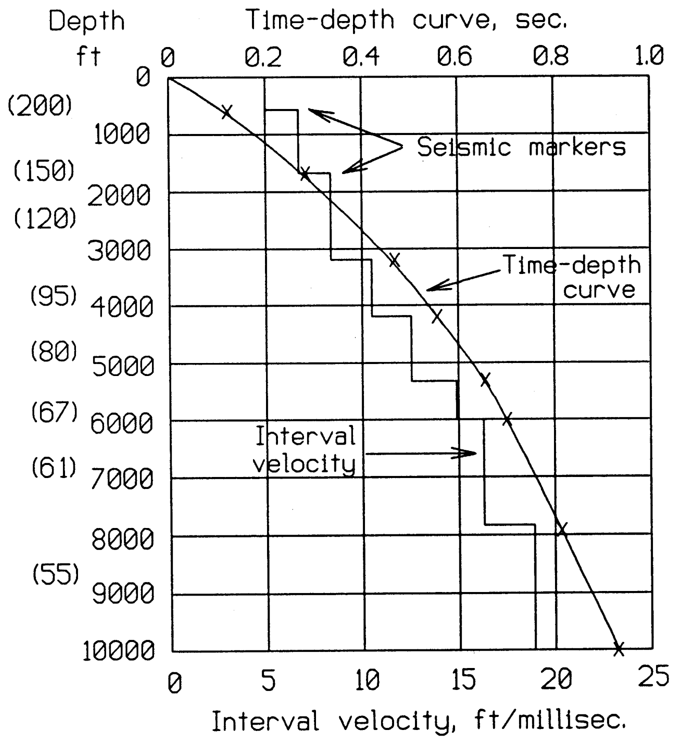


Fig. 16.14 Interval velocity and time-depth graphs.

16.10.3 Synthetic Seismograms

A synthetic seismogram is a seismic trace that has been constructed from various parameters obtainable from log information. It represents the seismic trace that should be observed with the seismic method at the well location. It is useful to compare such a synthetic seismogram with the seismic trace actually measured at the well to improve the picking of seismic horizons, and to improve the accuracy and resolution of formations of interest.

It should be remembered that the observed seismic trace is primarily a record of the ability of interfaces between formations to reflect elastic waves. This ability is called the reflection coefficient *R*. The reflection coefficient depends upon the properties of the rock either side of the interface, and in particular on its acoustic impedance. The acoustic impedance is the product of the seismic velocity and the density of the rock.

Thus, if we can derive the density and seismic velocity of a set of formations from logs, we can derive a synthetic seismogram. The procedure is as follows.

- Obtain a density log, $r(z)$, for the interval of interest. This is best obtained from a FDC log, but approximations can be made from the sonic log by using the sonic log to derive porosity, and then if the densities of the rock matrix and formation fluids are known, the density of the rock can be calculated.

- Convert the density log in depth to that against two-way time using the TTI information from the sonic log.

- Obtain the elastic wave velocity log, $V(z)$, from the sonic log using Eq. (16.1).

- Convert the elastic wave velocity log in depth to that against two-way time using the TTI information from the sonic log.

- Multiply these two values for each depth to give the acoustic impedance log, $AI = r(TWT)V(TWT)$.

- Calculate the reflection coefficient for each interface from the acoustic impedance log using;

$$R = \frac{AI_2 - AI_1}{AI_2 + AI_1} = \frac{r_2V_2 - r_1V_1}{r_2V_2 - r_1V_1} \qquad \textbf{(16.9)}$$

  where the subscript 2 refers to the formation below an interface, and the subscript 1 to the formation above it.

  Note that the reflection coefficient will only exist at interfaces, and is zero in between.

- Apply a multiplying factor to the reflection coefficient log to account for the fact that the seismic response will be attenuated with depth. This factor reduces with increasing two-way travel time (i.e., as depth increases).

- Convolve (multiply) the modified reflection coefficient with a chosen zero phase wavelet that represents the seismic data with which you wish to compare the synthetic seismogram.

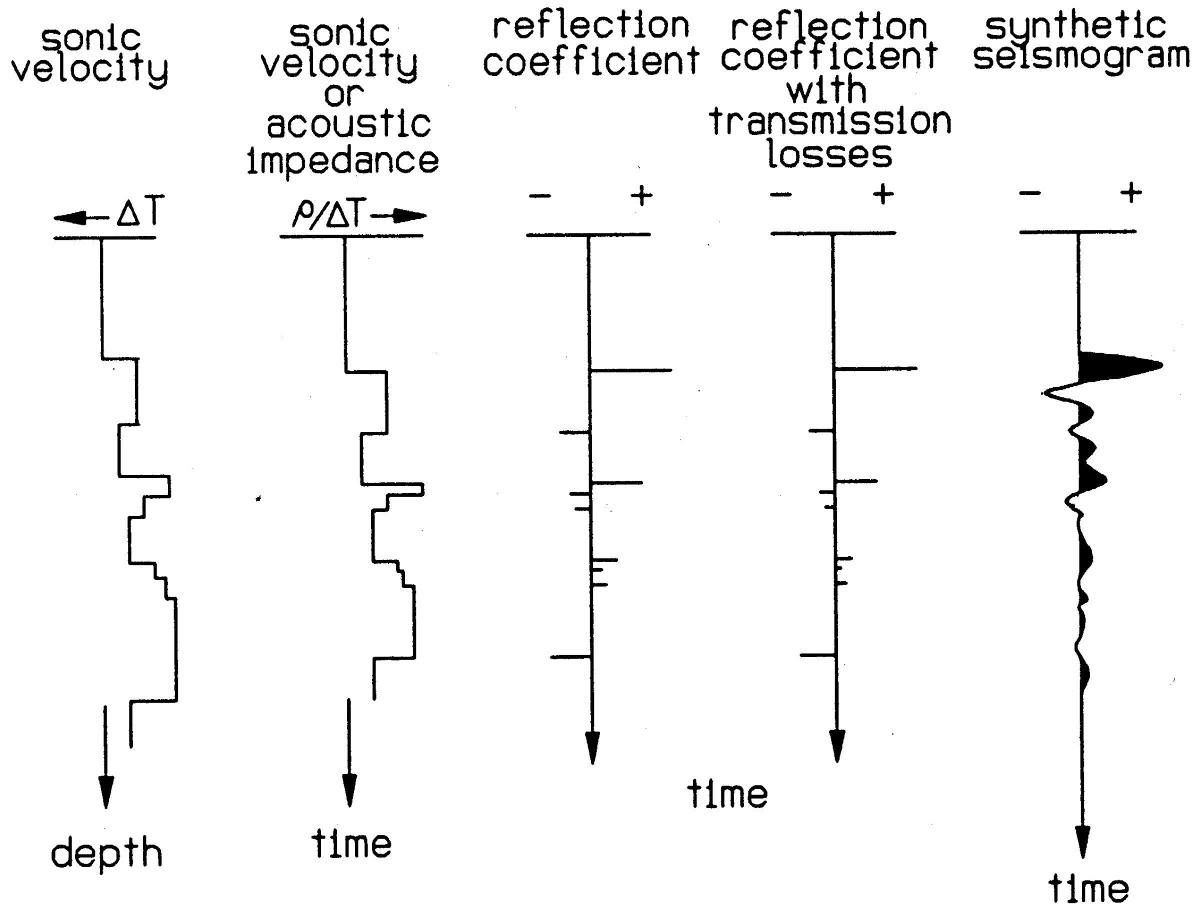


Fig. 16.15 The construction of a synthetic seismogram.

Note that the reverse procedure is also possible, and is used to obtain information about lithology and porosity (*via* density) (i.e., information about formation properties) from the seismic traces that are sensitive to the interfaces between formations. This is called *acoustic impedance inversion*, and is the domain of the geophysicist.

16.10.4 Porosity Determination

The sonic log is commonly used to calculate the porosity of formations, however the values from the FDC and CNL logs are superior.

It is useful in the following ways:

- As a quality check on the FDC and CNL log determinations.
- As a robust method in boreholes of variable size (since the sonic log is relatively insensitive to caving and wash-outs etc.).
- To calculate secondary porosity in carbonates.
- To calculate fracture porosity.

16.10.4.1 The Wyllie Time Average Equation

The velocity of elastic waves through a given lithology is a function of porosity. Wyllie proposed a simple mixing equation to describe this behaviour and called it the *time average equation* (Fig. 16.16). It can be written in terms of velocity or Δt:

$$\frac{1}{V} = \frac{f}{V_p} + \frac{(1-f)}{V_{ma}} \qquad \textbf{(16.10)}$$

$$\Delta t = f\, \Delta t_p + (1-f)\Delta t_{ma} \qquad \textbf{(16.11)}$$

Hence;

$$f_s = \frac{\Delta t - \Delta t_{ma}}{\Delta t_p - \Delta t_{ma}} \qquad \textbf{(16.12)}$$

where Δt is the transit time in the formation of interest, Δt_p is that through 100% of the pore fluid, and Δt_{ma} is that through 100% of the rock matrix, f is the porosity, and the velocities are analogous. A list of input values to these equations for common lithologies and fluids is given as Table 16.2.

Table 16.2 Values for Δt and V for use in Wyllie's time average equation.

Material	**D*t* (ms/ft.)**	***V* (ft./s)**	***V* (m/s)**
Compact sandstone	55.6 – 51.3	18000 – 19500	5490 – 5950
Limestone	47.6 – 43.5	21000 – 23000	6400 – 7010
Dolomite	43.5 – 38.5	23000 – 26000	7010 – 7920
Anhydrite	50.0	20000	6096
Halite	66.7	15000	4572
Shale	170 – 60	5880 – 16660	1790 – 5805
Bituminous coal	140 – 100	7140 – 10000	2180 – 3050
Lignite	180 – 140	5560 – 7140	1690 – 2180
Casing	57.1	17500	5334
Water: 200,000 ppm, 15 psi	180.5	5540	1690
Water: 150,000 ppm, 15 psi	186.0	5380	1640
Water: 100,000 ppm, 15 psi	192.3	5200	1580
Oil	238	4200	1280
Methane, 15 psi	626	1600	490

The Wyllie time average equation gives porosities that are overestimated in uncompacted formations (indicated by the rule of thumb that adjacent shale beds have Δt values greater than 100 microseconds per foot). An empirical correction B_{cp} is then applied:

$$f_s = \frac{\Delta t - \Delta t_{ma}}{\Delta t_p - \Delta t_{ma}} \times \frac{1}{B_{cp}} \qquad \textbf{(16.13)}$$

where B_{cp} is approximately equal to the value of Δt in the adjacent shales divided by 100.

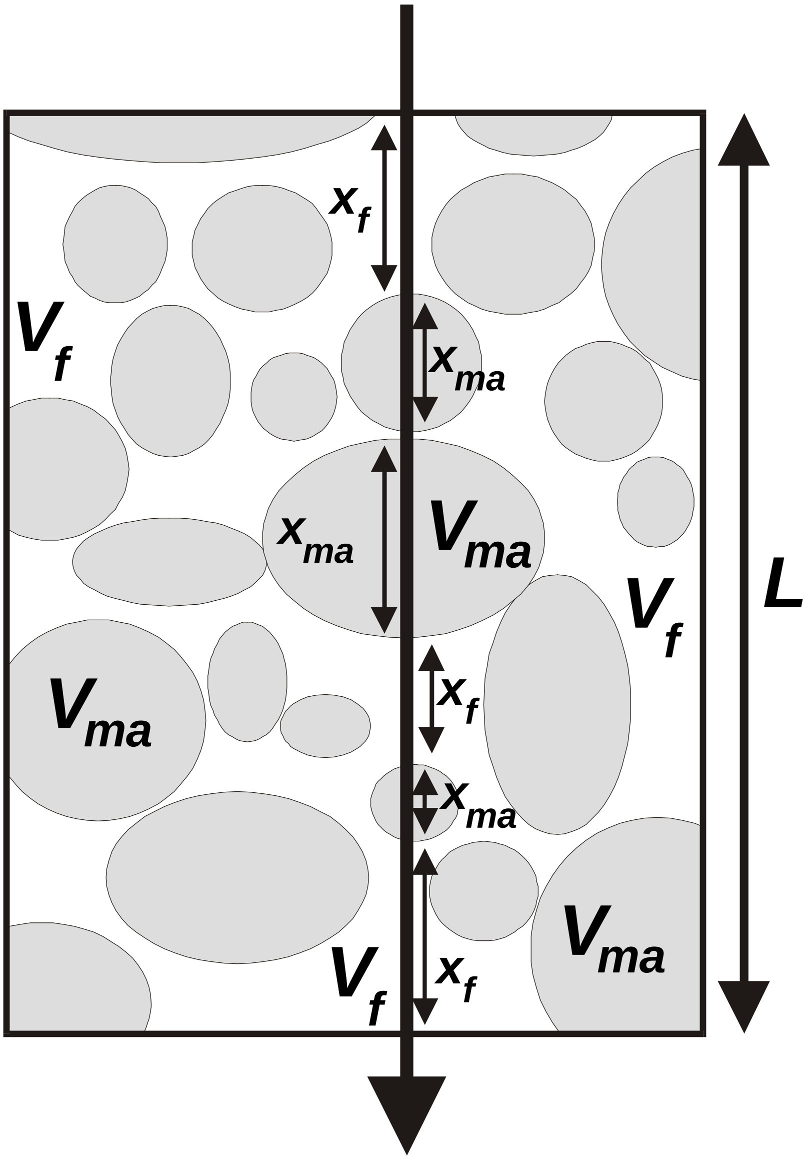


Fig. 16.16 The wave path through porous fluid saturated rocks.

The compaction correction factor can also be obtained from other logs:

- From the density log: A density-sonic cross-plot in clean water-bearing formations close to the zone of interest establishes a line that can be scaled in porosity units. But this is little better than using the density log to calculate the porosity directly.

- From the neutron log: The compaction factor is the ratio of the porosity from the uncorrected sonic log to that from the neutron log in clean water-bearing formations close to the zone of interest. Again, this is little better than using the neutron log directly to obtain the porosity.

- From the resistivity log: Obtain the porosity from the resistivity log in clean water-bearing formations close to the zone of interest using Archie's law and known values of its parameters. The compaction factor is then the ratio of the porosity from the sonic log to the porosity from the resistivity log. Again, this is little better than using the resistivity log directly to obtain the porosity.

Even though these methods are not so useful to obtain a corrected sonic porosity, they are useful if one wants to calculate the correction factor for its own sake.

16.10.4.2 The Raymer-Hunt Equation

Another method for calculating the porosity from the sonic log was proposed by Raymer. This is expressed as:

$$\frac{1}{\Delta t} = \frac{f}{\Delta t_p} + \frac{(1-f)^2}{\Delta t_{ma}} \tag{16.14}$$

This provides a much superior accuracy porosity over the entire range of geologically reasonable Δt. Figure 16.17 shows the Raymer-Hunt equation for some typical lithologies.

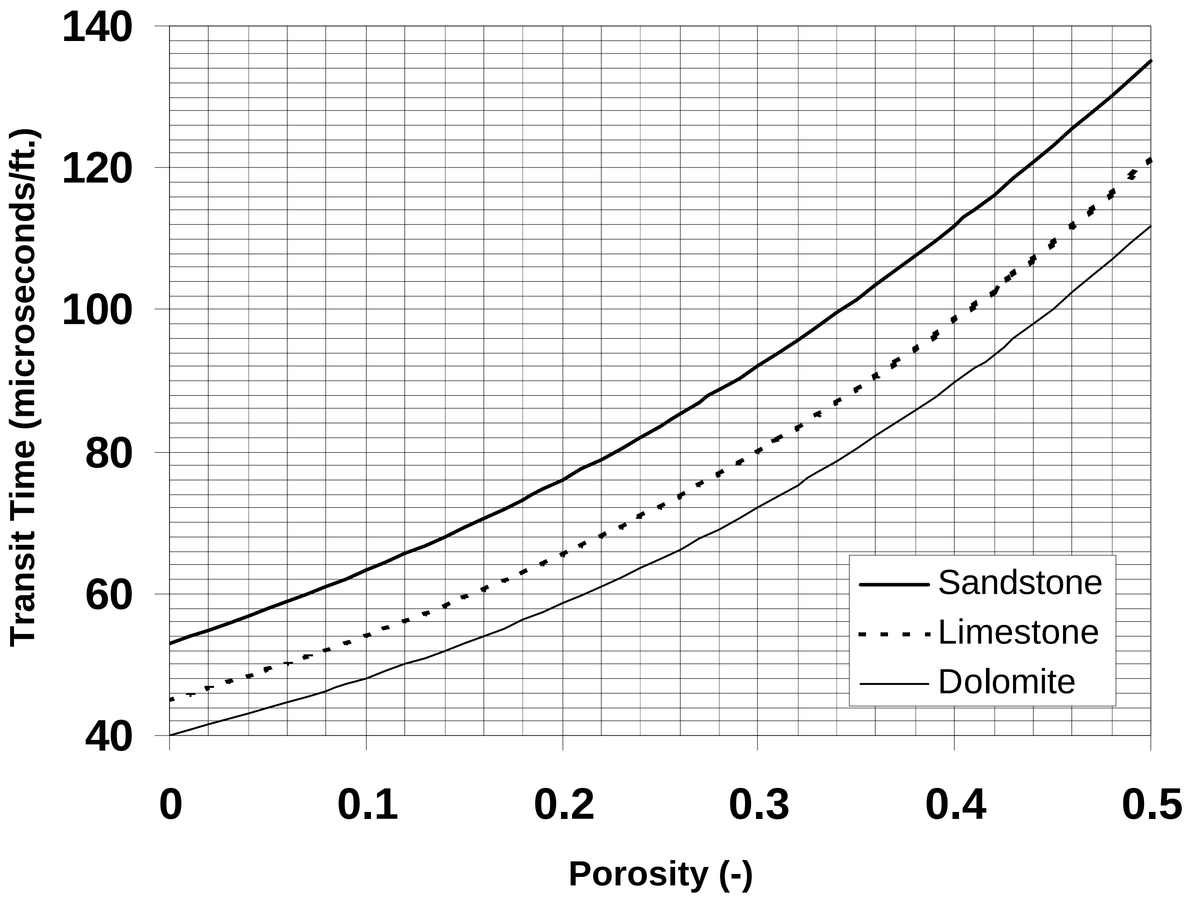


Fig. 16.17 The Raymer-Hunt equation for calculating porosity from transit time. Here the following data have been used: Δt = 53 (sandstone matrix), 45 (limestone matrix), 40 (dolomite matrix), 186 (fluid), all in μs/ft.

16.10.4.3 Calibration against Core

Occasionally, there is good core coverage in a well, so core porosities are available. If this is the case, it is useful to calibrate the sonic log against the core porosity. A cross-plot of core porosity against the transit time at the same depth should produce a straight line that can be extrapolated to the *x*-axis to give a value for the local matrix transit time Δt_{ma} (Fig. 16.18). This is best done for each obvious lithology in the well providing there are enough core determinations to ensure that the cross-plot for each lithology is worthwhile. Cross-plots can also be carried out between the core resistivity while 100% saturated with water, R_o, and the transit time from the sonic log. This should also give the local matrix transit time, and is a verification of the first plot.

The core porosity, sonic transit time cross-plot can also be used to calibrate the porosities derived from the sonic log between the cored points in a given well, but should not be extrapolated out of the cored interval or to other wells.

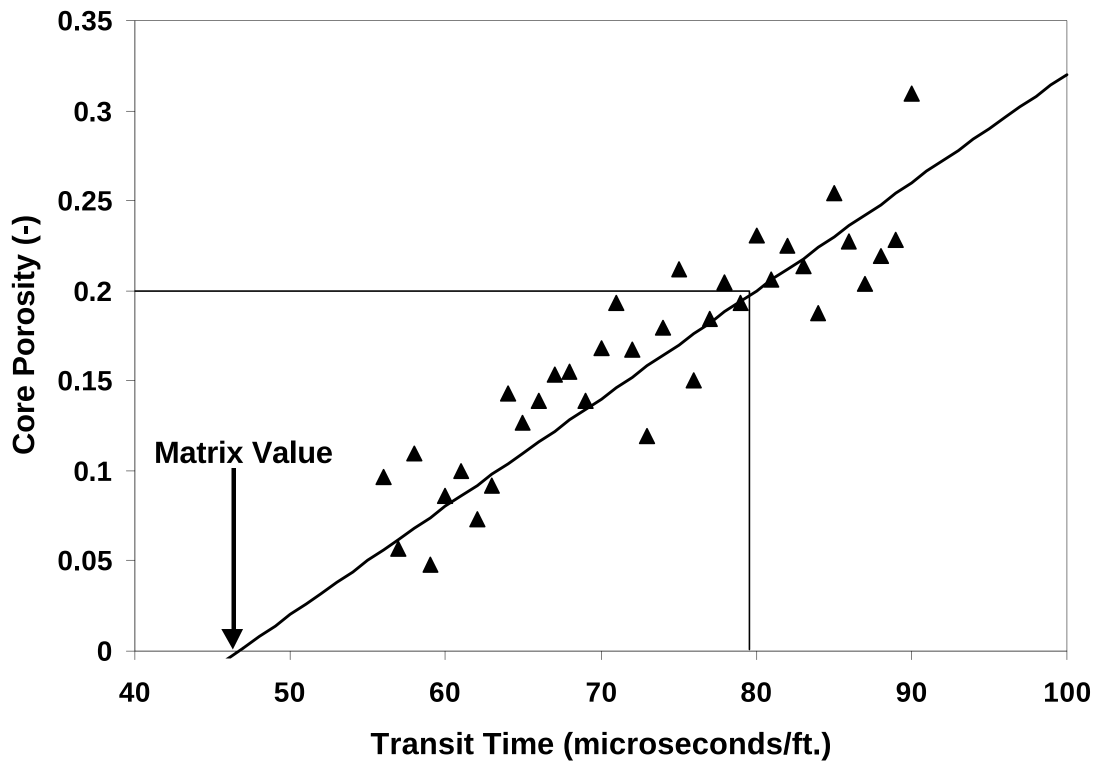


Fig. 16.18 Calibration against core porosities.

16.10.4.4 Secondary and Fracture Porosity

The sonic log is sensitive only to the primary intergranular porosity. By contrast, the density and neutron logs record the total porosity. The difference between the two measurements, therefore, can be used to calculate a value for the secondary porosity, whether it be isolated vugs in carbonates or fractures. This is called the *secondary porosity index* (SPI or f_2), and is defined:

$$f_2 = (f_N, f_D) - f_S \tag{16.15}$$

16.10.4.5 The Effect of Shale on the Sonic Derived Porosity

The effect of shales is very variable. This is because is depends upon the density of the shales, which varies a lot. Young shales are generally under-compacted and low density, tending to increase the transit times and hence give slightly higher sonic derived porosities. Exactly the opposite is the case for ancient compact shales with high densities, which give lower transit times and smaller porosities. The effect of shales on the porosity from the sonic log is not as great as the effect of gas.

16.10.4.6 The Effect of Gas on the Sonic Derived Porosity

Gas has a low density, and hence decreases the apparent density of a formation if present. This causes an increase in the sonic transit time, and hence a porosity that is overestimated.

However, the sonic tool penetrates to shallow levels, and senses the flushed zone. Most gas, even in high porosity gas-bearing formations will be replaced by mud filtrate. The remaining 15% or so will still have an effect upon the measure sonic transit time and the sonic porosity because of the very low density of the gas. An example is given as Fig. 16.19.

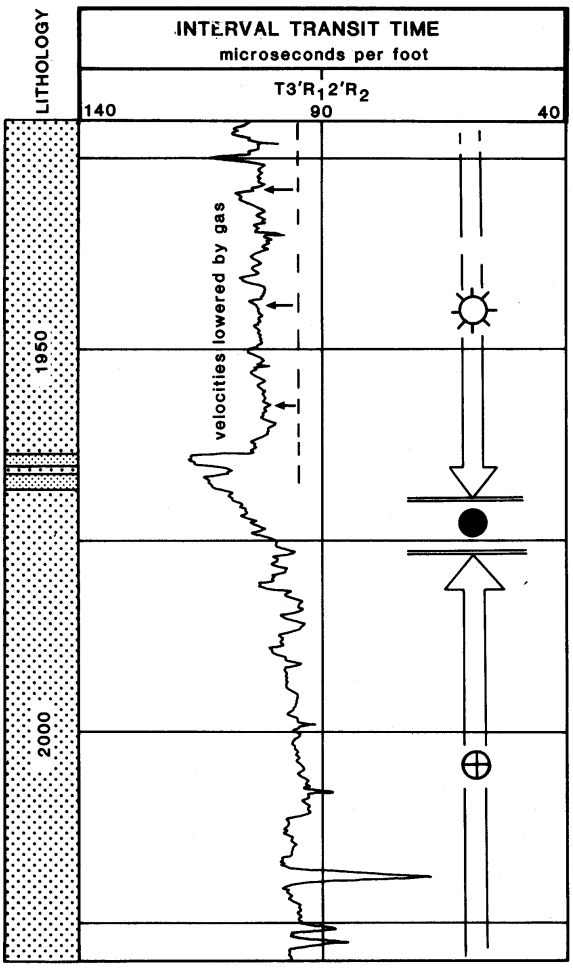


Fig. 16.19 The effect of gas on the sonic log.

16.10.5 Stratigraphic Correlation

The sonic log is sensitive to small changes in grain size, texture, mineralogy, carbonate content, quartz content as well as porosity. This makes it a very useful log for using for correlation and facies analysis (Fig. 16.20).

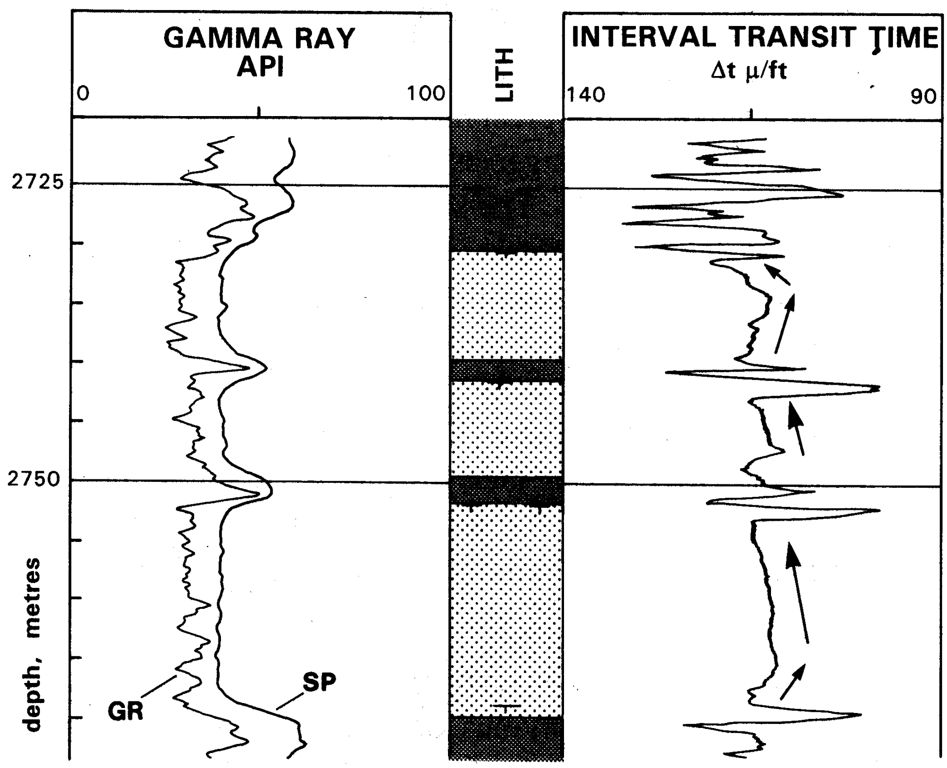


Fig. 16.20 Subtle textural and structural variations in deep sea turbidite sands shown on the sonic log (after Rider).

16.10.6 Identification of Lithologies

The velocity or interval travel time is rarely diagnostic of a particular rock type. However, high velocities usually indicate carbonates, middle velocities indicate sands and low velocities, shales.

The sonic log data is diagnostic for coals, which have very low velocities, and evaporites, which have a constant, well recognized velocity and transit time (see Table 16.2).

It is best to use the sonic log with other logs if lithological identification is important.

The main characteristics of the sonic log are shown in Fig. 16.21.

16.10.7 Compaction

As a sediment becomes compacted, the velocity of elastic waves through it increases. If one plots the interval transit time on a logarithmic scale against depth on a linear scale, a straight line relationship emerges. This is a compaction trend.

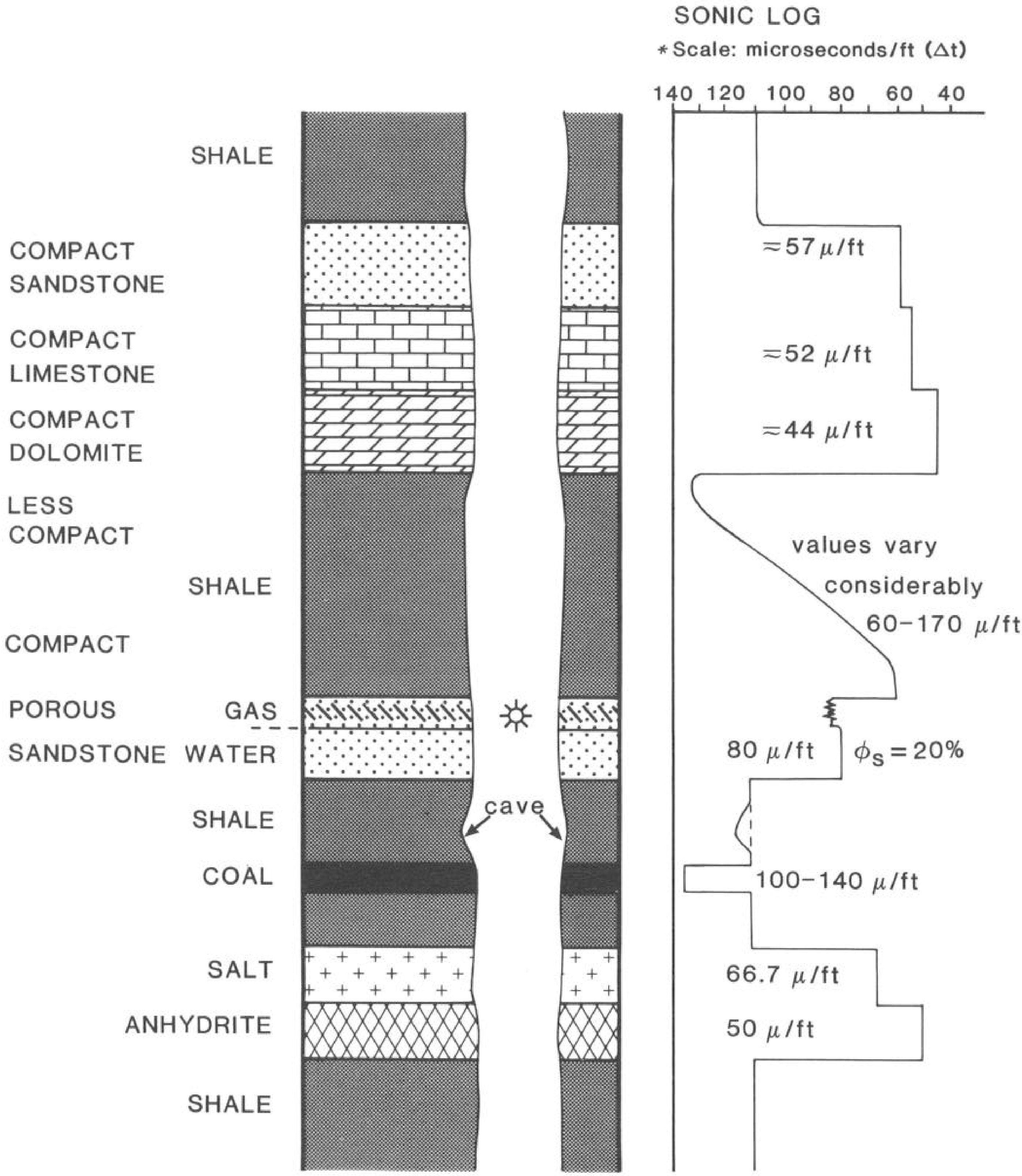


Fig. 16.21 Typical responses of the sonic log (courtesy of Rider).

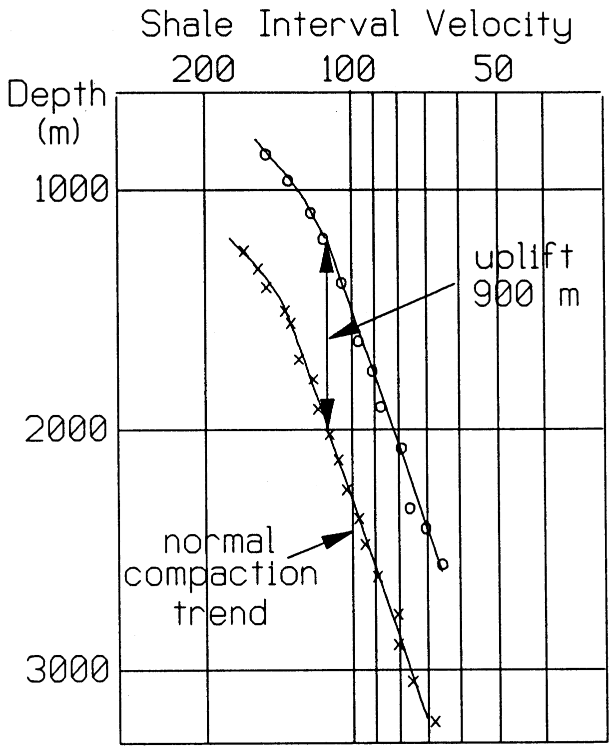
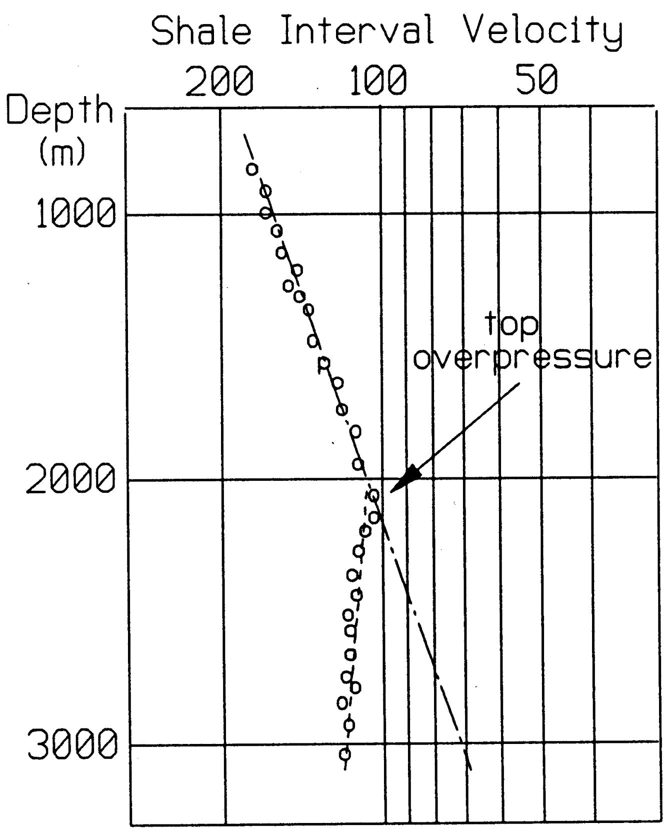


Fig. 16.22 Uplift and erosion from compaction trends.

Compaction trends are constructed for single lithologies, comparing the same stratigraphic interval at different depths. It is possible to estimate the amount of erosion at unconformities or the amount of uplift from these trends. This is because compaction is generally accompanied by diagenetic changes which do not alter after uplift. Hence the compaction of a sediment represents its deepest burial.

Figure 16.22 compares the compaction trend for the same lithology in the same stratigraphic interval in one well with that in another well. The data from the well represented by the circles shows the interval to have been uplifted by 900 m relative to the other well because it has lower interval transit times (is more compact) but occurs at a shallower depth.

Compaction curves such as these may therefore be extremely useful, as they can indicate the amount of eroded rock at sudden breaks in the compaction curve that are associated with faults of unconformities.



16.10.8 Overpressure

The sonic log can be used to detect overpressured zones in a well. An increase in pore pressures is shown on the sonic log by a drop in sonic velocity or an increase in sonic travel time (Fig. 16.23).

Plot interval transit time on a log scale against depth on a linear scale. In any given lithology a compaction trend will be seen. If there is a break in the compaction trend with depth to higher transit times with no change in lithology, it is likely that this indicates the top of an overpressured zone.

Fig. 16.23 An overpressured zone distinguished from sonic log data.

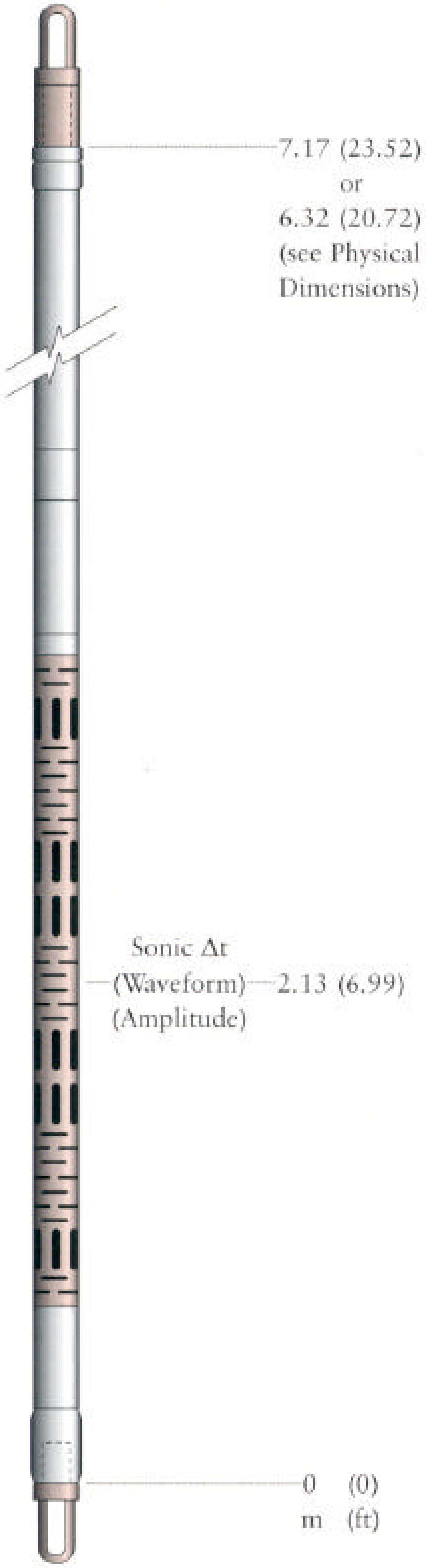


Fig. 16.24 The Compensated Sonic Sonde, CSS (courtesy of BPB Wireline Services).

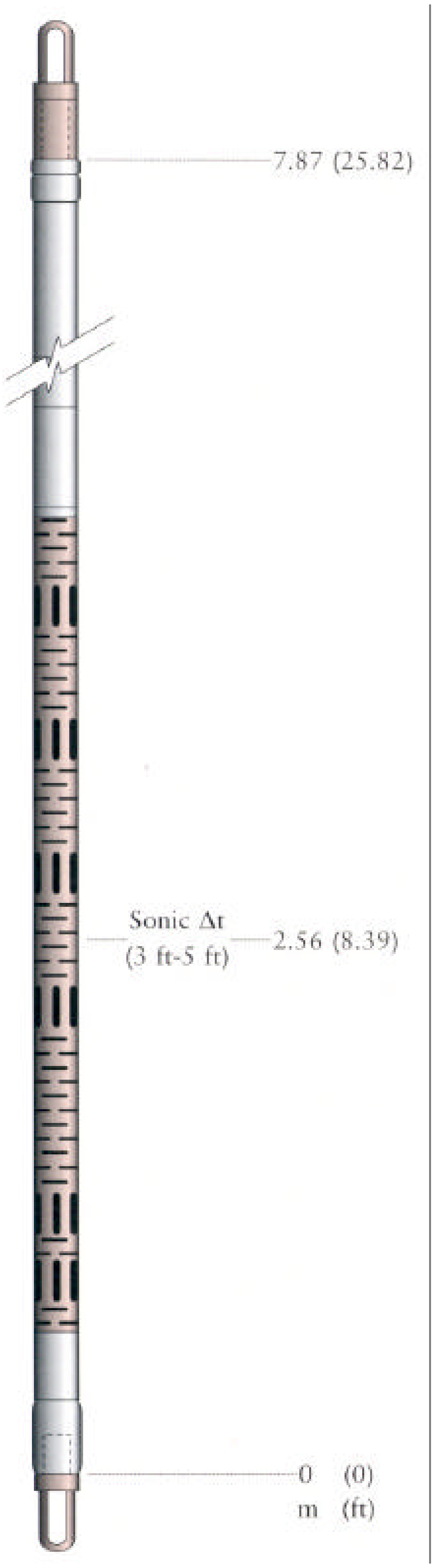


Fig. 16.25 The Long Spaced Compensated Sonic Sonde, LCS (courtesy of BPB Wireline Services).