Chapter 1

sonic or acoustic log

1.1 Introduction

Three main types of logging system are used for porosity determination.

They are:

1) sonic or acoustic log

2) Density log

3) Neutron log

Each system responds to different formation and fluids characteristics.

When used independently, additional information about the formation other than the sonde readings is required before porosity can be determined.

This additional information includes a knowledge of the formation's lithology and the type of fluids contained in the pore spaces of the formation being investigated .

Because the different porosity respond to different formation and fluid characteristics, combination's of two or all three of the devices can be used to solve for porosity and lithology, to differentiate between intragranular porosity and vuggy Porosity determination from an acoustic log is based upon the measurement of the travel time of an acoustic wave in the formation. When the travel time for the formation of interest is known, porosity can be calculated. The variations in acoustic travel time (Δt) are measured in μsec/ft and referenced to the value in limestone.

The neutron log measures porosity (φ) directly. Using limestone as the reference, porosity varies as a function of lithology and is shown either in percent or with respect to limestone.

On the density log, gas appears as an apparent increase in porosity (decrease in bulk density, (ϕb). The effects of changes in fluid saturation are predictable on density log due to the relationship between porosity, formation density and fluid densities. The variation of ϕb as a function of lithology is shown with respect to limestone value.

(The main text of this chapter on the sonic logs concerns the conventional, general purpose sonic tools that only measure compressional or P waves, the first arrival. A modern generation of tools is now able to measure the full wave train which includes the compressional wave, shear wave and Stoneley wave. These tools have more specialist applications and are considered in section…full waveform acoustic logs).

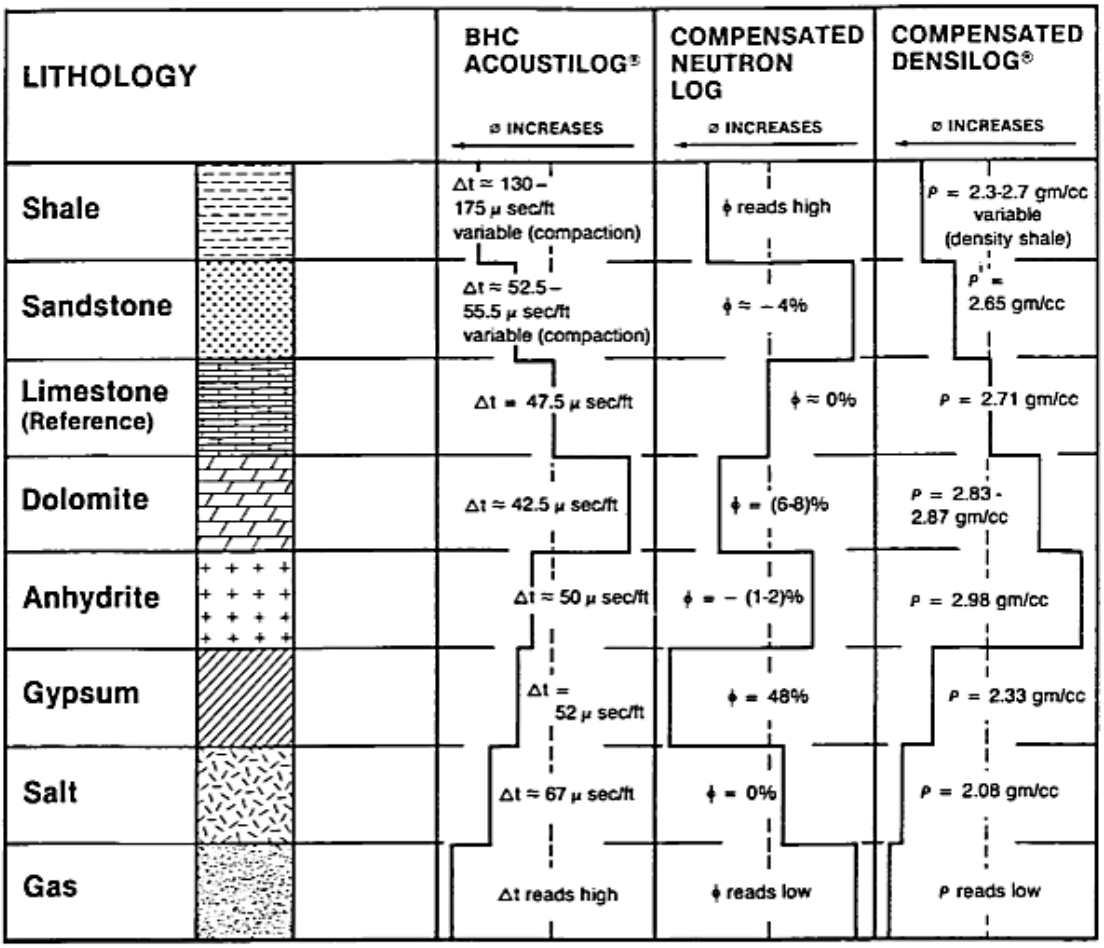


Figure 1.1 variation of instrument response to porosity.

1.2 GENERALITIES

The log

The sonic log provides a formation's interval transit time, designated Δt (delta-t the reciprocal of the velocity). It is a measure of the formation's capacity to transmit sound waves. Geologically this capacity varies with lithology and rock texture, notably porosity (figure 1.2)

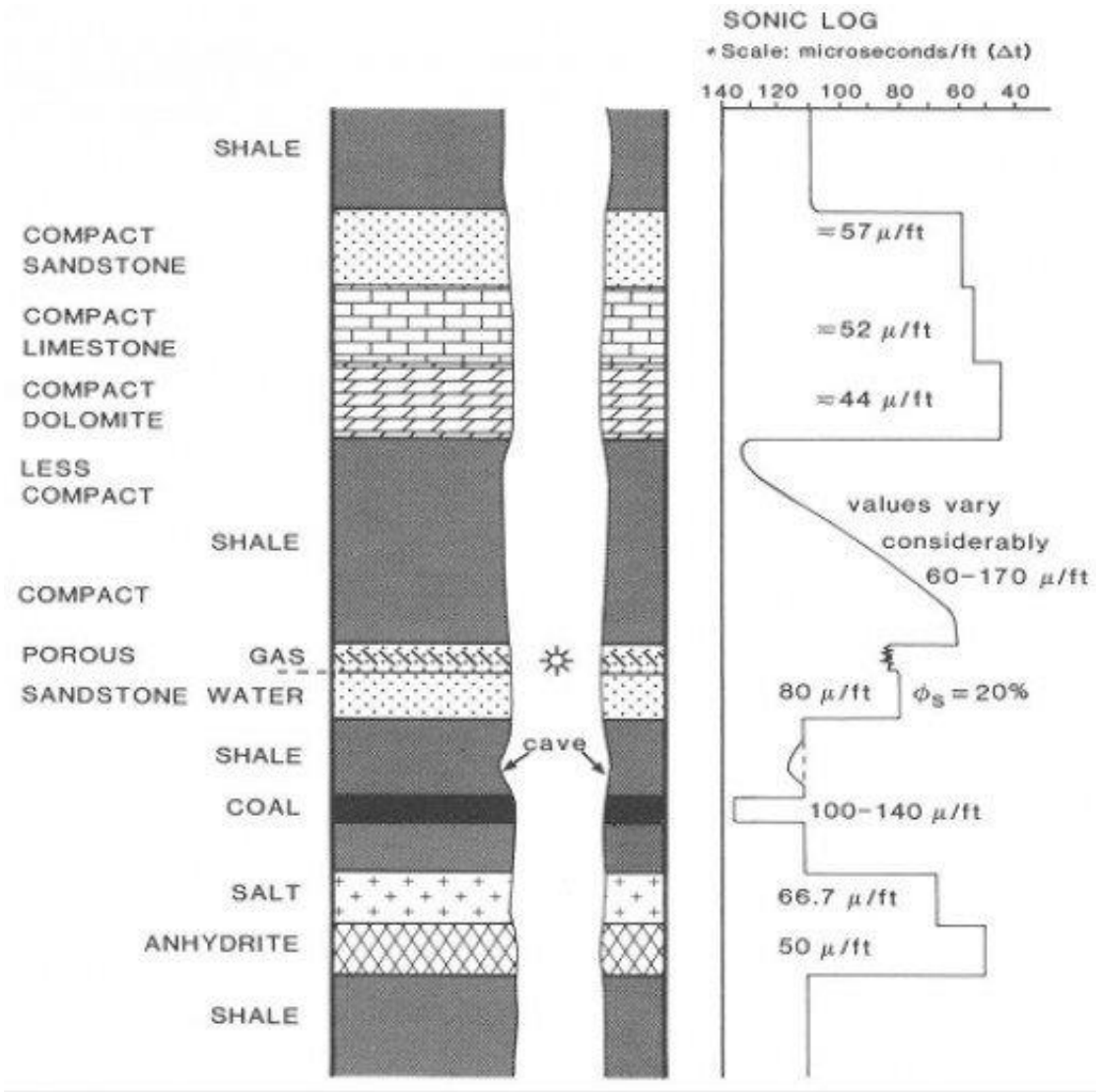


Figure 1.2 The sonic log: some typical responses. The sonic log shows a formation's ability to transmit sound waves.

Principal uses

Quantitatively, the sonic log is used to evaluate porosity in liquid-filed holes. As aid to seismic interpretation it can be used to give interval velocities and velocity profiles, and can be calibrated with the seismic section. Cross-multiplied with density, the sonic is used to produce the acoustic impedance log, the first step in making a synthetic seismic trace.

Qualitatively, for the geologist, the sonic log is sensitive to subtle textural variations (of which porosity is only one) in both sands and shales. It can help to identify lithology and may help to indicate source rocks, normal compaction and overpressure and to some extent fractures. It is frequently used in correlation (table 1.1)

Table 1.1 the principle uses of the sonic log (conventional), compressional wave tools).

	Discipline	Used for	Knowing
Quantitative	Petrophysics	Porosity	Matrix velocity Fluid velocity
	Seismic	Interval velocity	Integrated travel time Seismic markers
		Seismic calibration	Check shots
		Acoustic impedance	Direct use of sonic log
Qualitative and semi-quantitative	Geology	Lithology Correlation Texture	Matrix and mineral velocities
		Fracture identification	Density log porosities
		Compaction and overpressure	Normal compaction trends
	Geochemistry	Source rock evaluation	Resistivity log values

1.3 Principles of measurement

The conventional, general purpose sonic tools measure the time it takes for a sound pulse to travel between a transmitter and a receiver, mounted a set distance away along the logging tool. The pulse measured is that of the compressional or 'P' wave (Figure 1.3) and tool design enables the velocity of this wave in the formation to be measured. The compressional wave is simply the fastest or 'first arrival', in

which particles vibrate in the direction of the sense of movement. The compressional wave is followed by shear and Stoneley waves (Figure 1.3) which, in the conventional tools, are ignored but in the modem array acoustic tools, can be measured Typical sonic tool transmitters (transducers) are either magnetostrictive or, more commonly, piezoelectric and translate an electrical signal into an ultrasonic vibration. Receivers are usually piezoelectric, and convert pressure waves into electromagnetic signals which can be amplified to provide the logging signal. Piezoelectric materials have a type of structure which, when a stress is applied, shows separation of centres of negative and positive charge, thus creating a polarisation charge. It is this, amplified, which gives an electrical signal. In piezoelectric transmitters, the application of an electrical charge causes a change in volume which can be translated into a pressure pulse. A common piezoelectric material used is lead zirconate titanate or PZT.

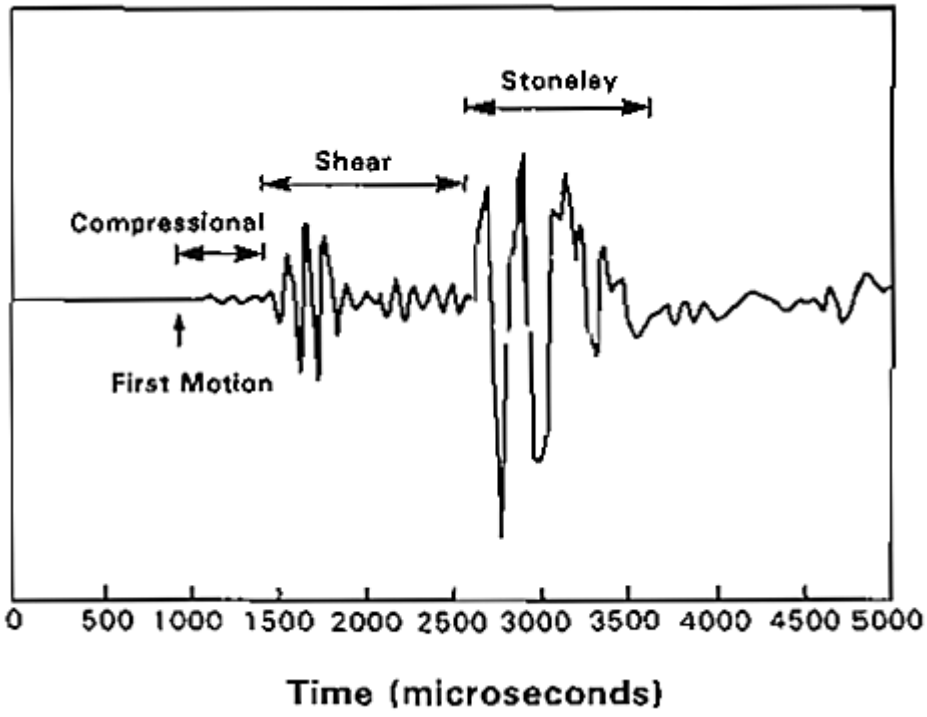


Figure 1.3 The full acoustic waveform that may be recorded in a borehole. The standard sonic records only the first arrival of the compressional (P) wave. Array sonic tools record the full waveform (modified from Ellis, J 987, after Schlumberger).

A sonic tool transmitter typically produces source frequencies of between 10000kHz (kilohertz) or 10,00040,000 cycles per second. At 10-20kHz, the acoustic wave has a wavelength of between 7.5cm (0.25ft) - 7Scm (2.5ft) over the velocity range of 15OOm/s (5000ft/sec) to 7500mls (25,000ft/sec). This is clearly a huge contrast to the typical seismic signal (sonic and seismic velocities are routinely compared) which has a content in the 10-50 hertz range (i.e. 10-50 cycles per second) and with wavelengths of 30m-50m.

1.4Tools

Modem sonic tools do not consist of just a single emitter and a single receiver, but of a number of both transmitters and receivers, the actual arrangement depending on the tool type. Modem designs allow unwanted borehole and tool effects to be largely eliminated and give a reliable measure of formation values even in quite poor borehole conditions. Typical tool design and use of compensation can be illustrated by the borehole-compensated (BHC) sonic tool (Figure 1.4).

The borehole-compensated sonic tool has two transmitter-receiver groups (one inverted), each group consisting of a transmitter coupled with a near receiver and a far receiver (Figure 1.4). Because the sonic is generally run hole-centred, any pulse transmitted by the tool, passes first into the mud, it is then refracted at the borehole wall, travels through the formation close to the borehole wall and, at a critical (slower) velocity is refracted back into the mud, so to reach the tool again where it is detected. A significant part of the trajectory is in the borehole mud (Figure 1.5). However, if this travel path is considered when one transmitter is used with two receivers (a near and a far), the mud effects can be eliminated. This is simply achieved by measuring the time it takes for the signal to reach the far receiver and from this subtracting the time it takes to reach the near receiver.

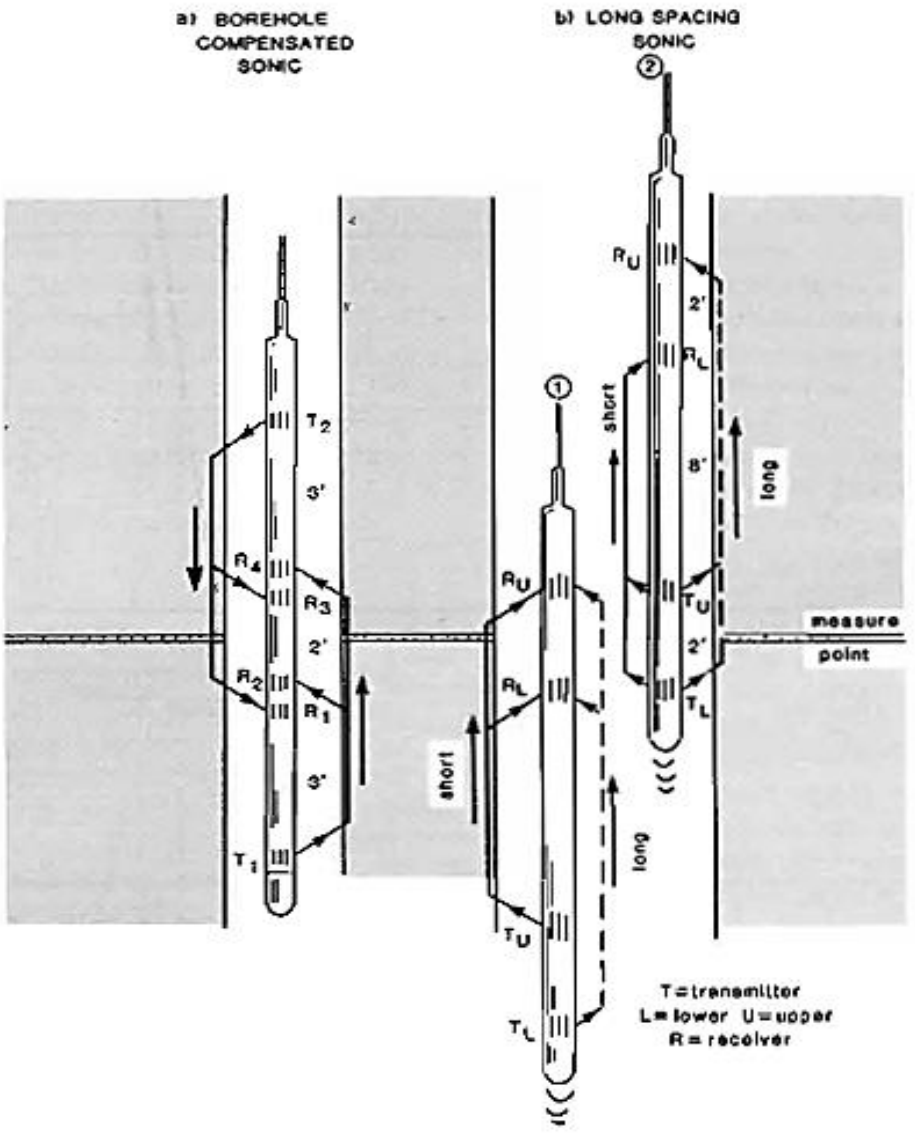


Figure 1.4 Sonic tools. Representations of (a) a borehole-cornpensated sonic tool which gives instantaneous readings with an inverted receiver transmitter array and (b) the Long Spacing Sonic Tool (Schlumberger) which gives long and short-spaced readings using a time (i.e, position) delay system: positions (I) and (2) are both relative to the same measure point. (Modified from Thomas, 1977 and Purdy, 1982).

The path from tool to borehole wall and back, in the mud, is effectively common to both trajectories, as is the section of the path between the transmitter and near receiver: all are eliminated on subtraction. What is not common to the two trajectories is the time taken between the two receivers (Figure 1.4), and this time is

the formation reading; the value required. Since tool tilt and hole size may make the common parts of the trajectory unequal, a second, inverted array (with a downward moving signal), is averaged with the first (with the upward moving signal) to provide compensation. This means that each value recorded on the sonic log is the result of a sequence of four separate transmitter-receiver readings, two from the lower transmitter to its near and far receivers and two from the upper transmitter to its near and far receivers. The up and down receiver sets are offset vertically to allow for the_ tool moving (Figure 1.4).

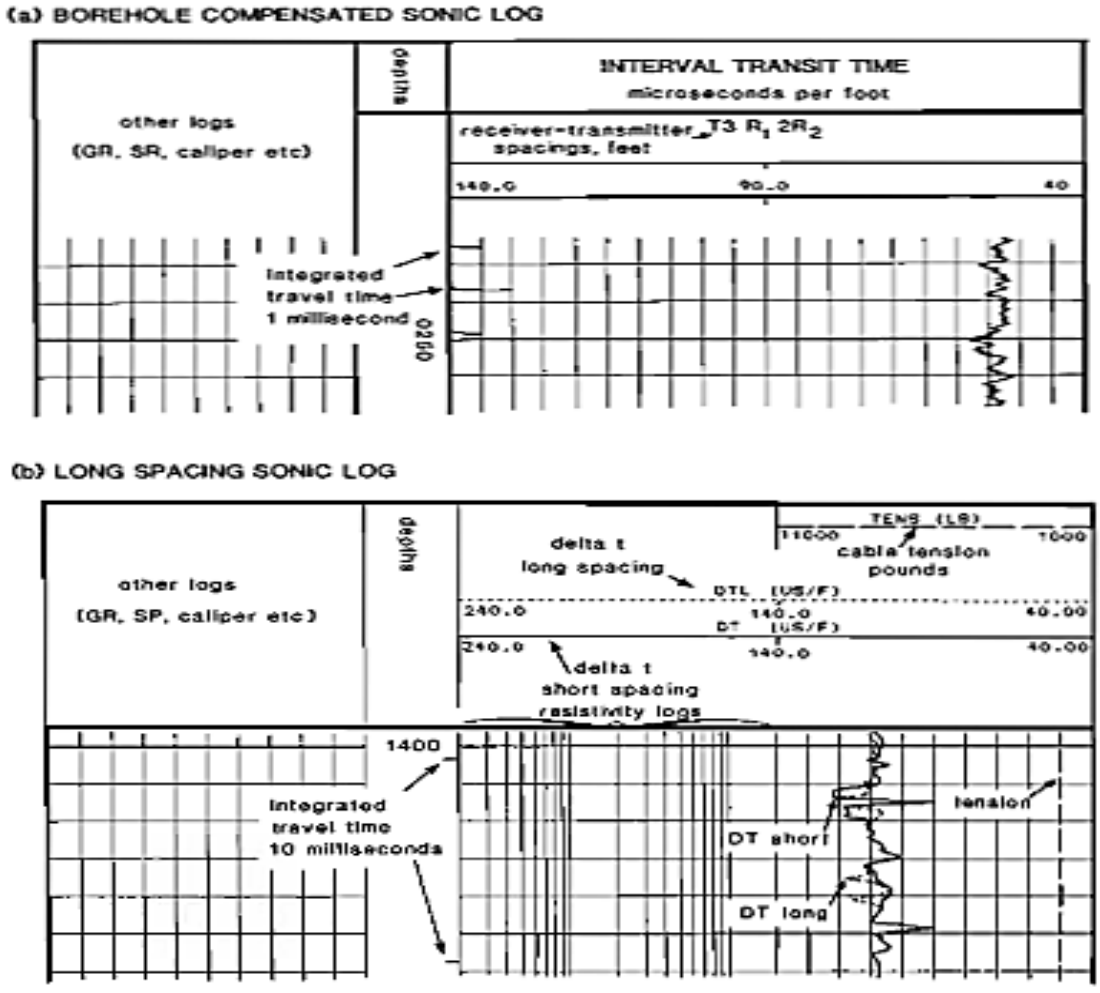


Figure 1.5 typical sonic log headings. (a) BHC tool (b) long spacing tool (on the ISF-sonic combination of Schlumberger).

In terms of typical values for the BHC tool, a transmitter pulse lasts between l00fLS - 200fLS (microseconds), the gap between the pulses is 50ms (milliseconds) or 20 pulses per second, allowing five complete sequences of four individual transmitter-receiver readings per second (figure1-4). At a typical sonic tool logging speed of 1500mJh (5000ftlh), (i.e. approximately 40cmlsec or 16"lsec) each complete sequence of four readings will give one log reading for every 5cm (3") of borehole. The borehole-compensated (BHC) sonic described above has a 'static' compensation and has been used commonly since the 1960s. It typically has transmitter-receiver distances of three feet and five feet with two feet between the two receivers (Figure1-5). In the late 1970s it was found that longer transmitter-receiver distances could help under certain borehole conditions and the long spaced sonic was designed with two receivers two feet apart separated by eight feet from two transmitters also two feet apart (i.e. the LSS of Schlumberger, Figure1-5, Table 1.2).

Table 1.2 the principal standard sonic tools .

Name	Mnemonic	Company
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	
Compensated Sonic Sonde	CSS	BPB
Long Spaced Compensated Sonic	LCS	
Borehole Compensated Sonic	BCS	Halliburton
Long Spaced Sonic	LSS	

This tool gives a near reading with 8-10 foot spacing and a far reading with 10-12 foot spacing (Figure1-6). Because of its length, the long spaced sonic has a 'dynamic' compensation system where depth memorisation is employed. To complete a full compensation sequence for both the near and far readings, the tool must record a full transmitter-receiver sequence at two depth positions separated by 10 feet, the tool's compensation shift. The system is diagrammatically illustrated (Figure1-6).

Log presentation, scales and units

Sonic values are given in microseconds (us) per foot (1 microsecond = 1 X 10^{-6} seconds). The value is called the interval transit time and is symbolized as Δt (Figure1-7). The most common interval transit times fall between 40μs and 140μs: this is the arithmetic sensitivity scale usually chosen for the log (Figure1-7). The velocity is the reciprocal of the sonic transit time, i.e., velocity ft/s = $\frac{1}{\Delta t}$ us/ft, Even on logs with a metric depth scale, the transit time is mostly still given in us/ft. The necessary conversions must be made to extract the metric velocity, velocity, thus:

$$\Delta t = 40\mu s \text{ from the sonic log.}$$

$$\text{Velocity} = \frac{1}{40 \times 10^{-6}} = 25{,}000 \text{ ft/sec} = 7{,}620 \text{ m/s}$$

When a sonic tool is run on its own it is presented in full width track 2 and 3. If, as is often the case, the sonic log is combined with other tools, the log appears only on track 3, often with the sensitivity scale of 4Oμs- 140μs maintained (Figure An *integrated travel time* (or TTI) is recorded simultaneously with most sonic logs. It represents a time derived from the average velocity of the formation logged and plotted over the vertical depth of the interval in milliseconds ($l0^{-3}$ seconds) each millisecond appearing on the inside depth column as a bar. Each I0ms is a longer bar (Figure 1.5). Adding the milliseconds and dividing by the thickness of the interval covered gives the velocity. The TTI milliseconds may be added together to correspond to the travel times on the seismic section: seismic sections are in two-way time, that is TTIx 2. The sonic tool is frequently run in combination with the resistivity logs (e.g. Schlumberger ISF-Sonic tool; Wireline Acoustic log-Resistivity tool). It is best run hole-centred, although modem tools may be centred, especially in large holes.

1.4 Log characteristics

Depth of investigation

The path of the compressional waves detected by sonic tools is essentially along the borehole wall with very little penetration, generally between about 2.5cm to 25cm (1"'-10") from the borehole wall (Dewan 1983; Chernali etal., 1984). The penetration is independent of receiver separation and depends on the signal wavelength; the greater the wavelength the greater the penetration. For a particular frequency therefore, penetration is greater in higher velocity formations.

This simple picture is complicated by the observation that mechanical and chemical damage at the bore hole wall can have an effect on sonic response (Blakeman, 1982). Damage can create a low velocity zone around the borehole. When this occurs, increasing the transmitter-receiver distance on a sonic tool increases the compressional wave penetration, which was the reason for the introduction of the long spaced sonic sonde. The increase in investigation occurs because the compressional wave in the damaged zone is slower than the wave in the undamaged formation. If the transmitter-receiver distances are large enough, these two waves become separated and it is the faster, deeper penetrating wave which is detected as the first arrival. For example, with borehole damage, while the standard sonde has a depth of investigation of 15cm - 25cm (6"-10"), the long spaced tool has an investigation of 38cm - 50cm (L5"-20·'). Consequently, a long spaced sonic has a greater chance of detecting the compressional wave from undamaged formation. In the reverse physical situation, in gas zones where the invaded formation, with fluid saturation, has a faster velocity than the virgin formation saturated with gas, a difference in penetration is still said to exist. In this case the standard sonic will have a very small investigation, 5cm (2"') or less while the long spaced tool may reach 25cm (10·') (Chernali et al., 1984). Through experience, however, the effects of wall damage on the standard sonic appear to have been exaggerated and the effectiveness of the long spacing sonic not demonstrated, a meaningful separation of the long and short spaced readings seldom being observed. The standard tool remains effective in most cases. In short, although there are variations, the depth of investigation of all sonic tools is small and the detected wave is generally from the immediate borehole wan or the invaded zone in permeable intervals.

Bed resolution

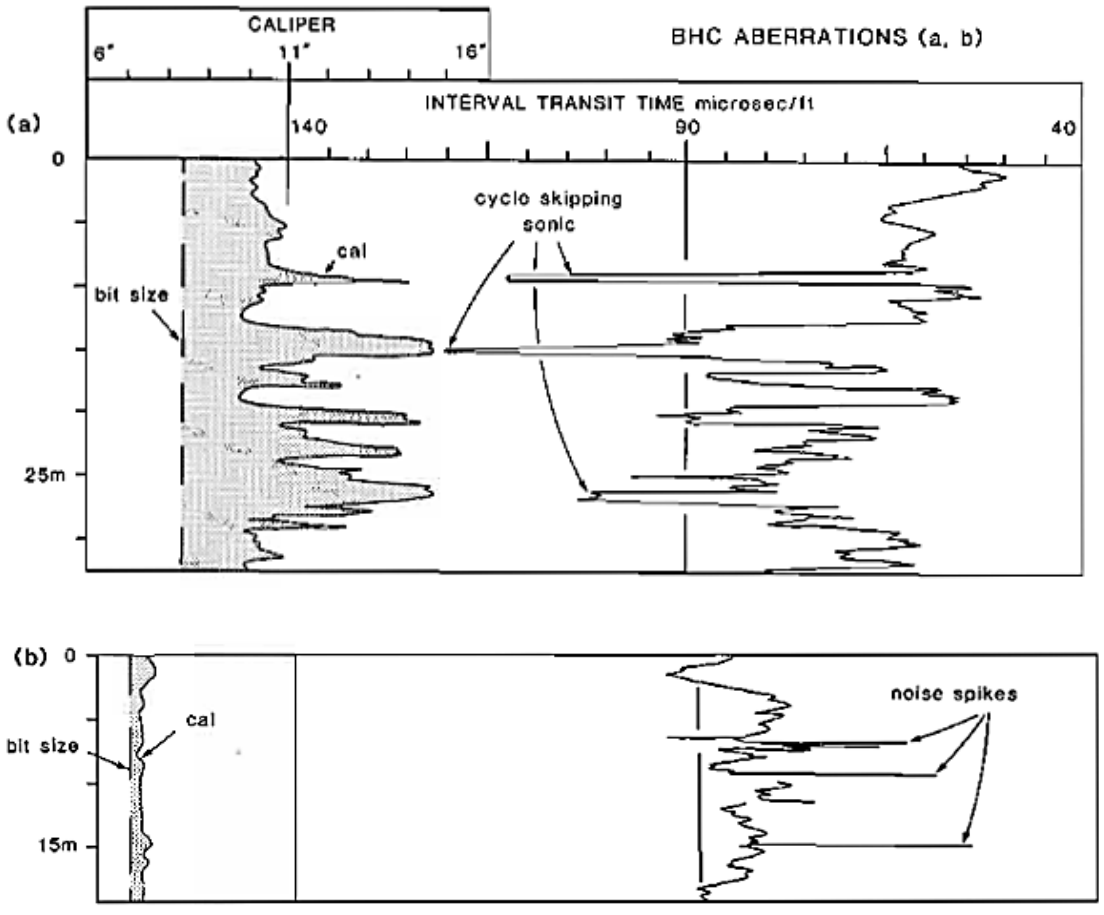
The vertical resolution of the sonic is the span between receivers for the borehole compensated tools and should be similar for the long-spacing tools (Figure 1.4). This is frequently two feet (6lcm). Beds of less than 60cmthickness will be registered on the sonic log, but a true velocity will not be recorded. Specialist tools now exist with much higher resolutions.

Unwanted logging effects

The conventional borehole-compensated sonic is very robust, even in poor and over-sized holes (cf. Ellis, 1987) due to the effectiveness of the compensation system (see 'tools' above). However, in extremely poor holes, cycle skipping occurs (Table 1.3). This is the effect when the first, compressional wave arrival is too attenuated (weak) to activate the receiver, which is only tripped by a subsequent arrival: the recorded time is therefore too long (interval transit rime too large) (Figure 1.6). The reverse situation occurs when noise signals trip a receiver. This causes noise spikes on the log and is found in hard formations such as limestones (Figure 1.6). While the conventional sonic is robust, the long spaced sonic is not. There are two weaknesses in the tool which are compounded, signal attenuation and the dynamic compensation system. Attenuation results in a signal too weak to trigger a receiver, and causes cycle skipping. In the dynamic compensation system, each transmitter-receiver reading is used twice (Le. at two levels) and an error on anyone of the eight readings comprising a full sequence, causes paired errors on the log (Figure 1.6). Paired errors and serious cycle skipping are frequent on many long spaced sonic recordings despite computer smoothing' (Table 1.3) (Purdy, 1982)

Table 1.3 Unwanted environmental effects - sonic log.

Factor	Effect on log	Severity*
Caving	'Cycle skipping'	Present
	Diminished Δt troughs to a mud value (BHC)	
	High or low or alternate paired anomalous peaks (LSS)	Common
Hole rugosity	'Noise triggering'	Rare
	Increased Δt spikes (BHC)	
	High or low or alternate paired anomalous peaks (LSS)	Common



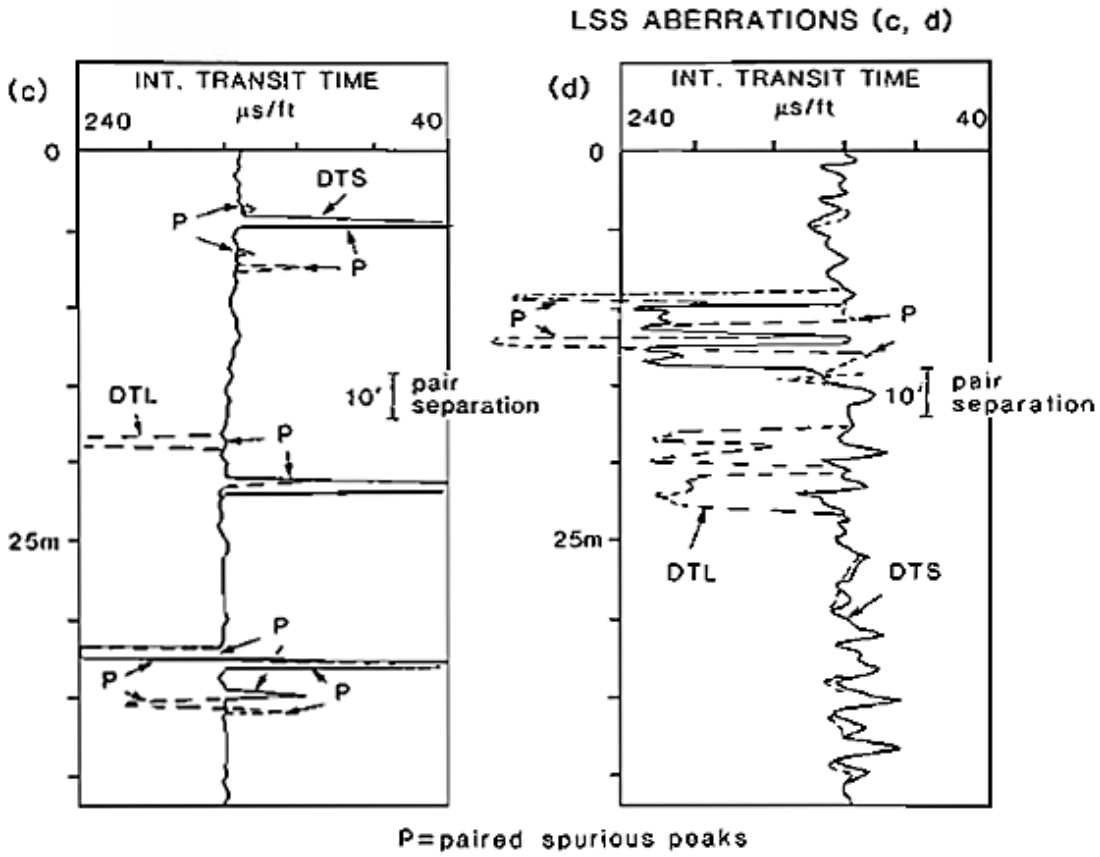


Figure 1.6 Unwanted environmental effects on the sonic log. (a) BHC tool, cycle skipping; (b) BHC tool, noise spikes; (c, d) long-spacing tool, paired aberrations; DTS = short-spaced sonic, DTL = long-spaced sonic. The pairs are separated for the most part by l0ft, the compensation shift distance.

1.5 Quantitative uses

The sonic log can be used to calculate porosity, although it is usually inferior to neutron or density-log calculated values.

To use the log it is necessary to propose that when a formation has, on average, a uniform distribution of small pores and is subjected to a heavy confining pressure, there is a simple relationship between velocity and porosity (Wyllie et *a*,l1956).

$$\frac{1}{V} = \frac{\phi}{V_L} + \frac{1-\phi}{V_{ma}} \qquad (1)$$

which can be written, replacing Δt for v, as

$$\Delta t = \phi \Delta t_L + (1-\phi)\Delta t_{ma} \qquad (2)$$

where V = tool-measured velocity; V_L = velocity of the interstitial fluid; V_{ma} = velocity of the matrix material; ϕ = porosity; Δt = tool measured interval transit time; Δt_L = transit time of interstitial fluid; and Δt_{ma} = transit time of matrix

Equation simply states that the transit time measured by the tool is the sum of the time spent in the solid matrix and the time in the fluid; it is called the time average relationship (Wyllie et al., 1956). This 'time' is a function of the matrix velocity and constituents volumes (i.e. wave path length) (Figure 1.7). The relationship is best translated into graphic form, where it becomes obvious that the measured interval transit time has a linear relationship with porosity (Figure 1.8). The relationship will vary depending on the velocity of the matrix material (see equation 2). Some of the more common matrix velocities are shown in Table 1.4.

The quantitative derivation of porosity using the time average relationship is usually imprecise and modifications are necessary (Raymer et al., 1980) although these are often only effective very locally (Brereton and McCann, 1990).

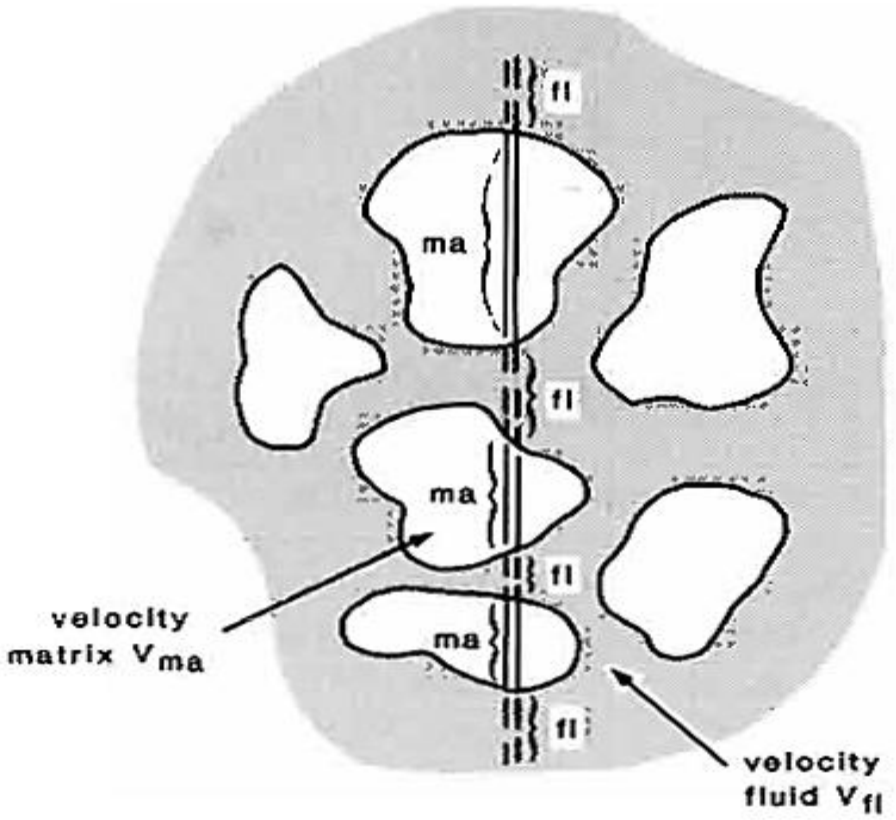


Figure 1.7 diagramatic representation of the path of P waves through a rock, showing the relationship between time spent in the matrix (V_{ma}) and time in fluid (V_{fL}) giving the basis for the calculation of porosity from sonic velocities.

Clearly, the physical relationship between porosity and sonic velocity is still to be explained. From experience, the effect which causes most deviation from the simple law is lack of compaction (i.e, external pressure), when porosities are very high, especially in sandstones. However, recent work has shown that the failure of the time average equation in fact covers the whole range of porosities (Brereton and McCann, 1990) (Figure 1.9). For a particular set of known matrix velocities, the time average formula always over-estimates the porosity. The simple schematic representation illustrated (Figure 1.7) of a straight wave path through a sediment is, not surprisingly, incorrect. If an incorrect ray path is the cause of the general error, then the path through the fluid is longer than expected (or shorter through the matrix), hence the overestimation of porosity. This is only one possibility.

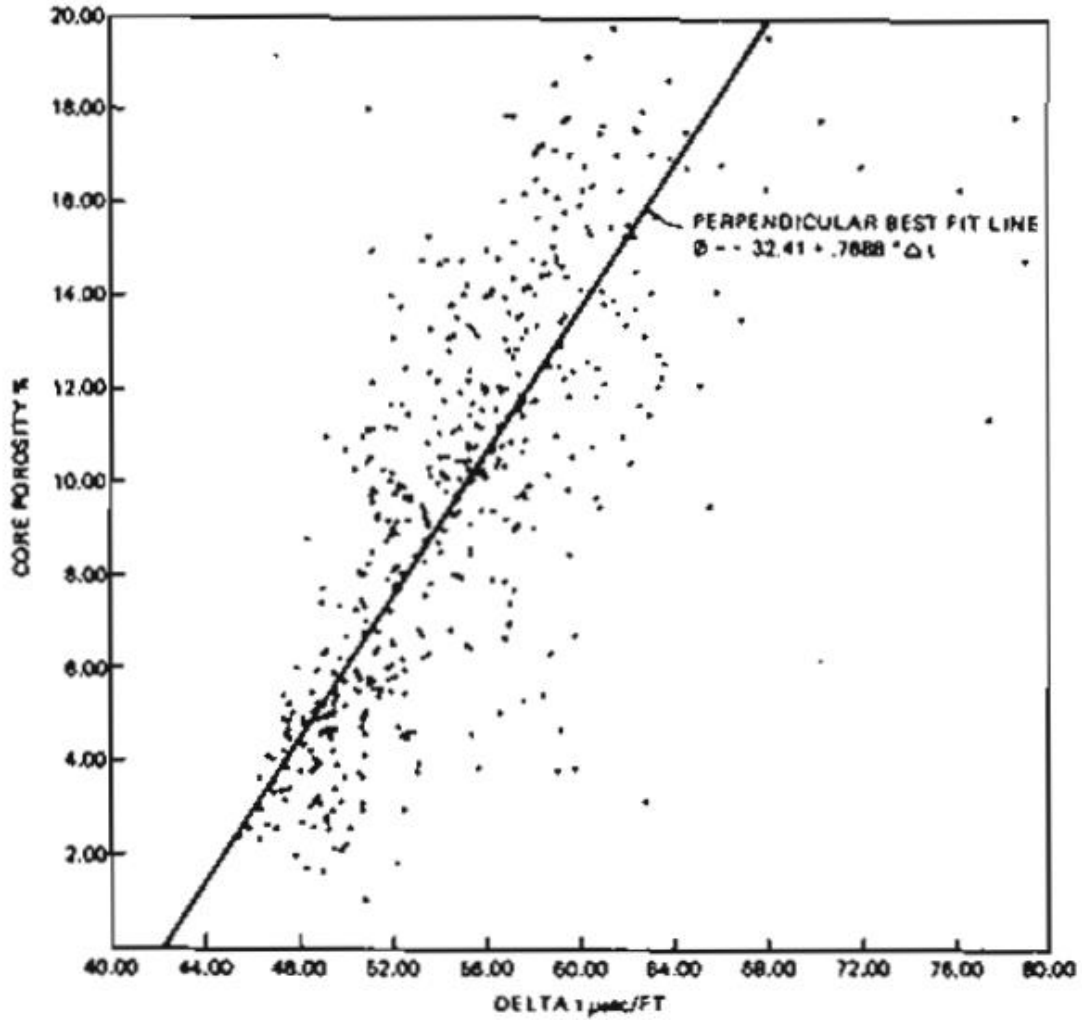


Figure 1.8 Interval transit time compared to measured porosity in a dolomite. (From McFadzean, 1973).

For unconsolidated sediments, most logging companies provide compaction correction coefficients, based on cross-plotting sonic porosities and density- or neutron log porosities. It is, however, best to avoid using the sonic log to calculate porosity in unconsolidated formations.

When gas replaces liquid in the formation, the time average graph no longer applies (i.e., VI.- is replaced by VI and V). Even though the sonic pulse does not penetrate deeply into the formation, there is often sufficient gas in the invaded zone to affect the velocity. Indeed, the effect can be used to identify gaseous hydrocarbons when a gas/water contact is present (Figure 1.10). To estimate the real porosity in the

presence of gas, the porosity calculated from the raw log should be multiplied by between about 0.7-0.8, but this is only an estimate.

To calculate porosity in the presence of shale the sonic log must be corrected for a shale volume derived from other logs.

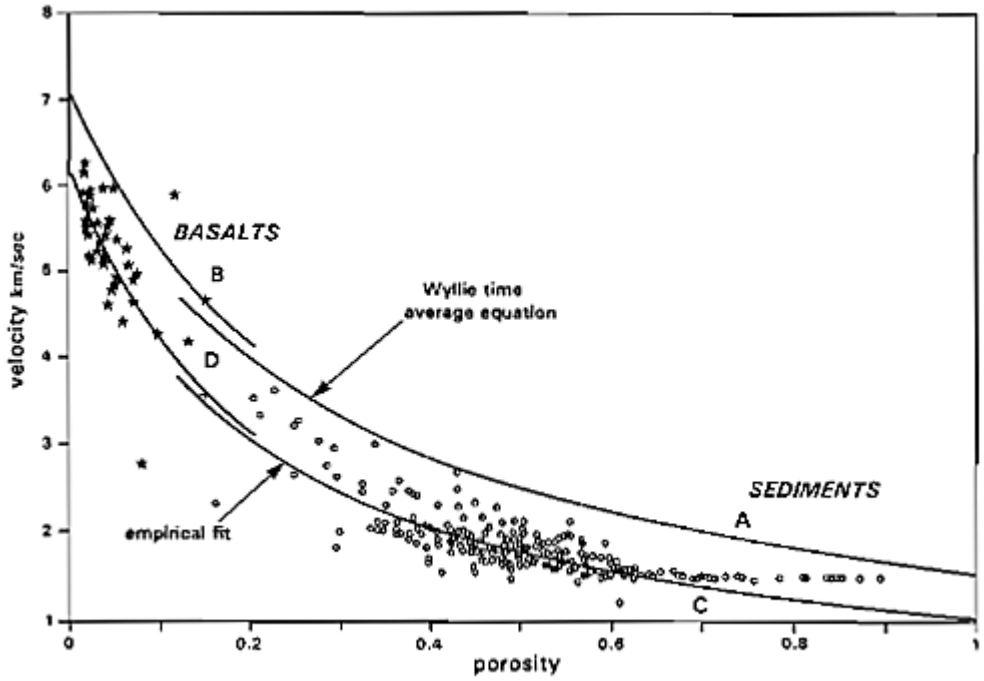


Figure 1.9 Porosity predictions from the Wyllie 'time average equation' in (A) sediments (calcareous oozes), (E) oceanic basalts. Empirical curve fit for (C) sediments and (D) oceanic basalts. The indication is that the Wyllie equation overestimates porosity across a wide range of values (from Brereton and McCann, 1990).

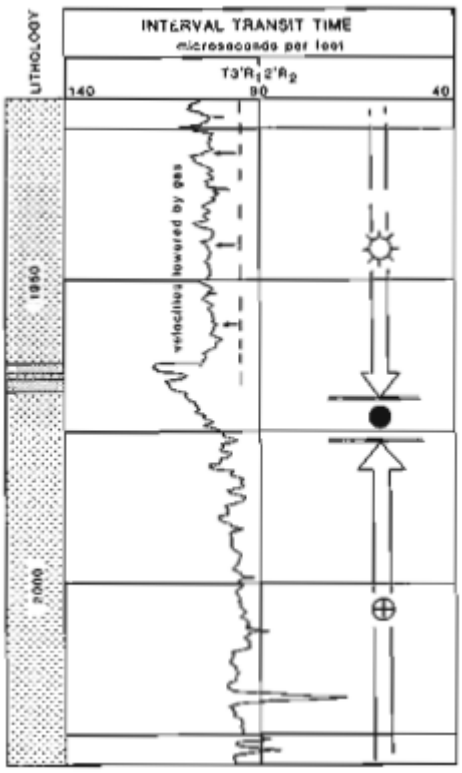


Figure 1.10 The effect of gas on the sonic log. The sonic velocity in this porous sandstone is lowered by about 8%.

1.6 Quaulitative uses

Lithology identification

The velocity of the common sedimentary rock types is rarely diagnostic of lithology; there is too much variation within each type and too much overlap between types (Table 1.4, Figures 1.11, 1.12).

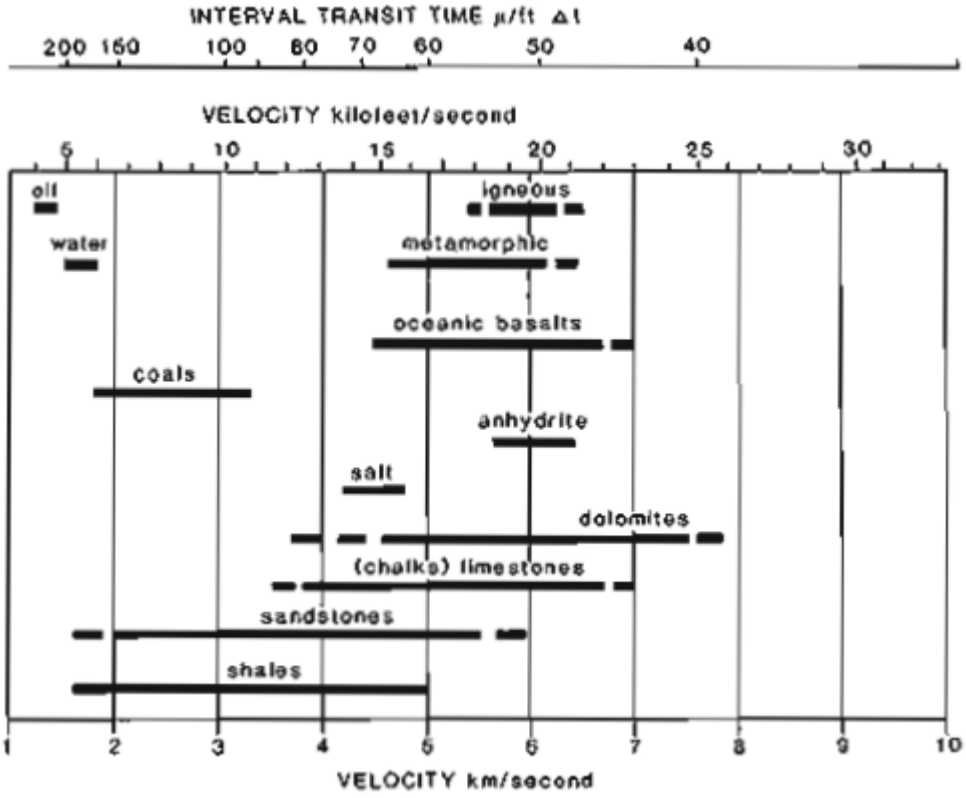


Figure 1.11 The average velocity ranges of common lithologies compared. The considerable amount of overlap indicates that velocity alone is seldom diagnostic of lithology (values are for depths typical of oil exploration wells).

Table 1.4 some typical sonic matrix velovities (see also figure 1.11) (from Shclumberger, 1972; serra. 1972; Gearhrt, 1983).

	Δt_{ma}(μ/ft)	V(m/s)	V(ft/s)
Sandstones (compacted)	55.5–51	5490–5950	18,000–19,500
Quartz	55.1	5530	18,150
Limestones	53–47.6	5800–7000	19,000–23,000
Calcite	46.5	6555	21,500
Dolomites	45–38.5	6770–7925	22,200–26,000
Dolomite	40	7620	25,000
Shale	167–62.5	1600–5000	5000–16,000

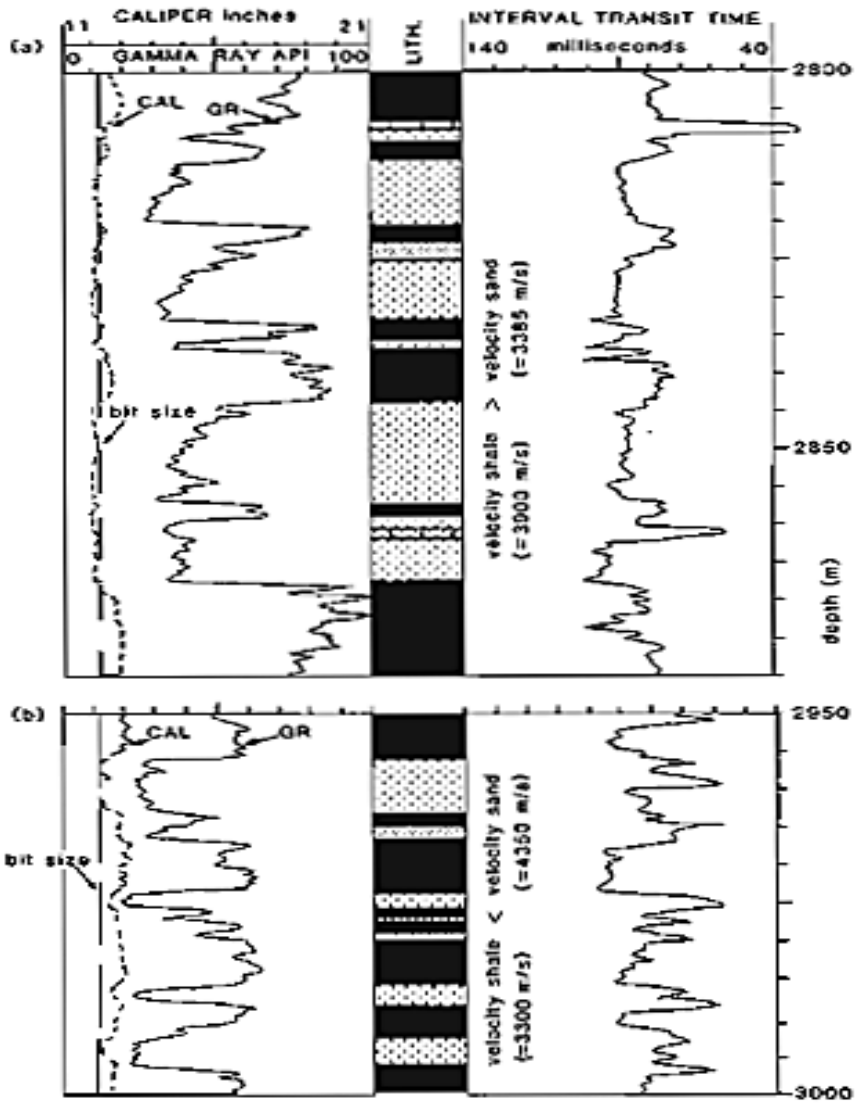


Figure 1.12 Sonic log in sand-shale sequences. (a) The sands have a lower sonic velocity (about 3385m/s) than the shales (3900m/s). (b) The reverse, where the sands have higher velocity (about 4350m/s) than the shales (3300m/s). Sonic velocities are therefore not diagnostic of lithology.

However, such is the natural occurrence that high velocities are more likely to be associated with carbonates, middle velocities with sands and shales and low velocities with shales (Figure 1.11). Velocity, nonetheless, is diagnostic of coals, which have unusually low values (high interval transit times) (Figure 1.13). It is also diagnostic of the evaporites, which are essentially chemically pure substances with predictable physical properties, (rock salt), gypsum and anhydrite (Table 1.5). Moreover, halite velocities do not vary with depth.

Table 8.5 Some diagnostic (mineral) velocities (from Serra, 1979; Gearhart, 1983; Schlumberger, 1985).

	Δt(μs/ft)	Velocity*(m/s)	Velocity*(ft/s)
Water (saline)	189–200	1610–1525	5290–5000
Halite	66.7–67	4550	15,000
Anhydrite	50	6100	20,000
Gypsum	52–53	5860	19,000
Anthracite	90–120	3050	≃ 10,000
Lignite	140–180	2000	≃ 6500
casing (steel)	57.8	5270	17,300

*Averages

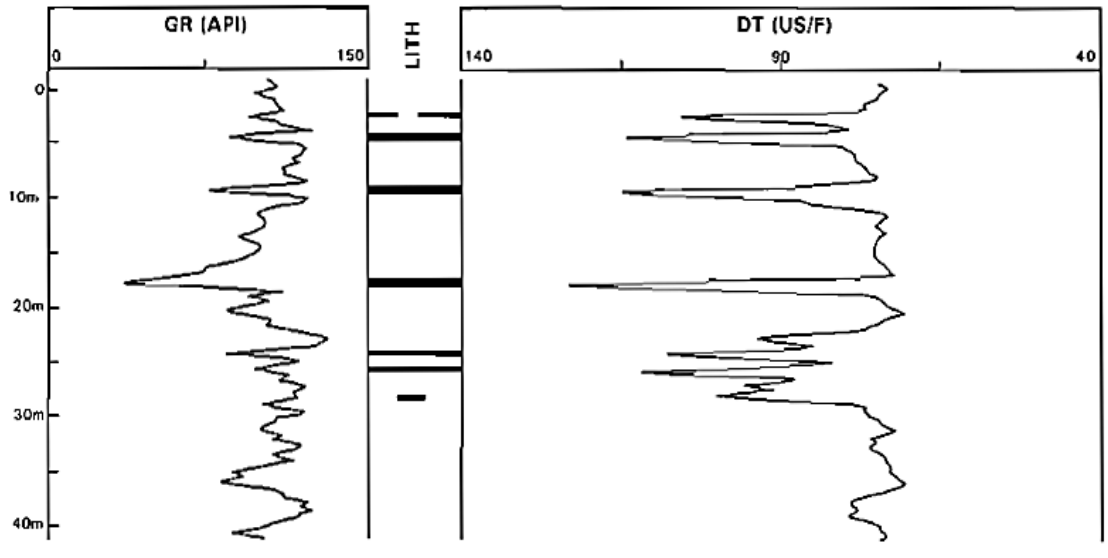


Figure 1.13 Distinctive sonic log response in coals. The interval transit time is characteristically very high (low velocity).

Texture

Although sonic response may not be diagnostic in terms of lithology, it is very sensitive to rock texture, even subtle changes. The way in which sound travels through a formation is intimately associated with 'matrix, matrix materials, grain size distribution and shape, and cementation' (Wyllie et al., 1956), in other words texture (Figure 1.7). This is true for most lithologies and in fact extends upwards in scale to include also structural characteristics such as bedding. For example, the sonic has a very distinctive response to slumped, debris flow intervals in the Upper Cretaceous chalks of the North sea.

Over a cored interval where the chalk bedding characteristics can be detailed, intervals of debris flow, which have chaotic textures and no bedding, show distinctly higher interval transit times (lower velocity) than normal chalk which is generally thin-bedded (Hauon, 1986).

It is probable that the sensitivity of the sonic to bedding, as well as to texture at a smaller scale, is because the detected signals physically travel up (and down) through the formation. Any horizontal feature, such as bedding, must be crossed and will affect the response. This is well illustrated in shales where finely laminated intervals have a different response to massive intervals. The example (Figure 1.14) shows a shallow marine shale cycle in which the laminated section at the base shows higher interval transit times (lower velocity) than the more massive, upper section. In many cases the exact textural effects causing the sonic log response may not be known and the difficulty in calculating porosity from the sonic is a demonstration of this. An example of textural changes in turbidites is an illustration (Figure 1.15). The consistently low gamma ray response suggests that there are no cornpositional changes and yet the sonic shows distinct variations. Undoubtedly porosity change occurs, but there are also changes in grain size and bedding (sedimentary structures). It is not possible to extract, separate and identify each individual influence.

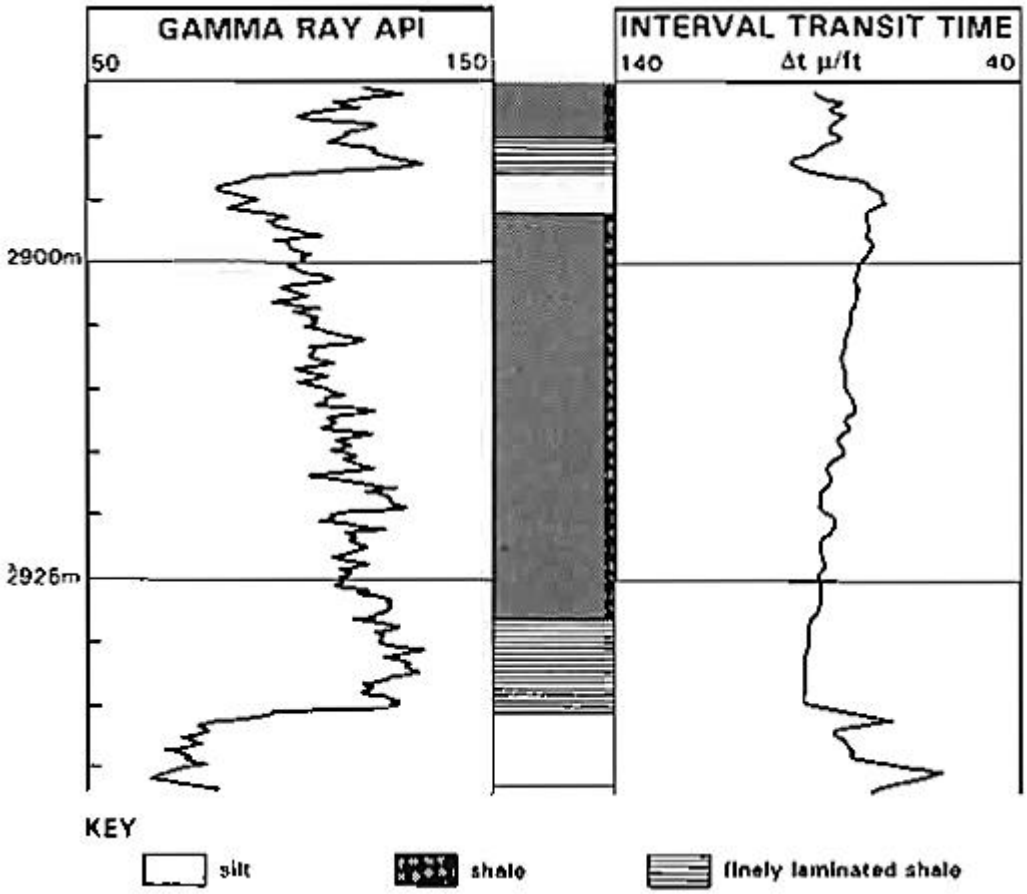


Figure 1.14 Sonic response to shale structure in a shallow marine, coarsening-up sequence. The finely laminated shales at the base of the sequence show a high interval transit time (low velocity), while in the more massive, bioturbated, silty upper parts of the sequence, interval transit times are lower (velocity higher).

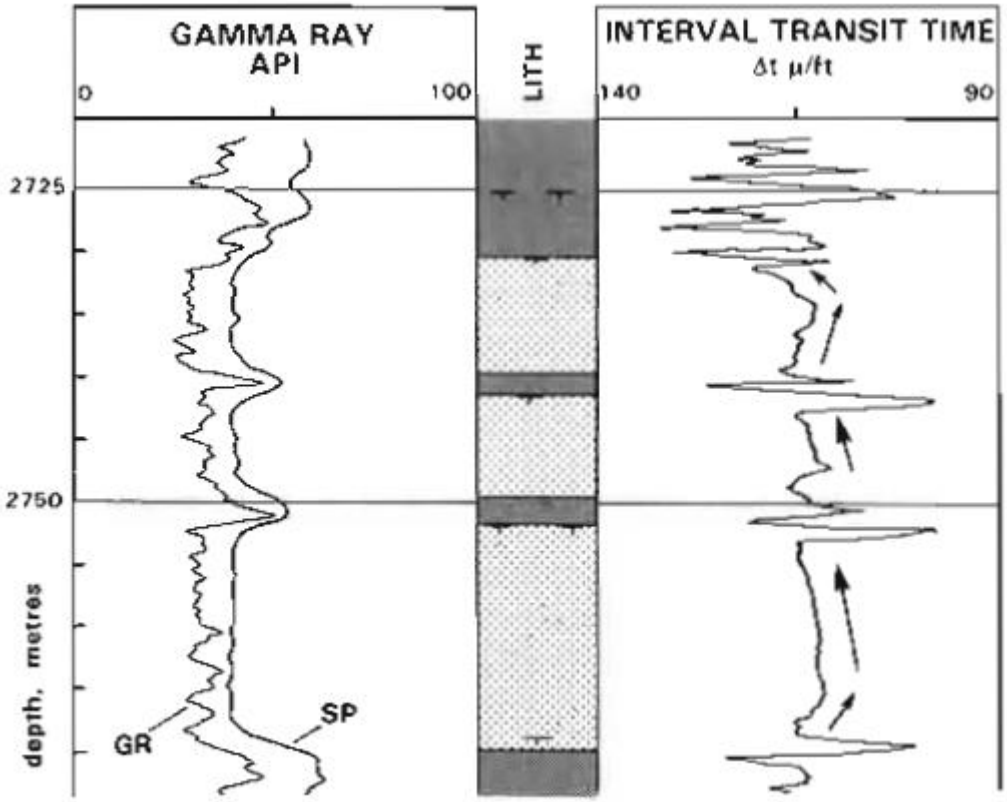


Figure 1.15 Subtle textural and structural variations in deep sea, turbidite sands, shown on the sonic log. The log changes indicate variations in grain-size, texture and structure but which dominates in this example is not known.

Correlation - sonic log character

The sonic transit time of a formation is a very distinctive characteristic although, as indicated, the precise textural and lithological (compositional) causes are difficult to define. Rather like colour, it is not diagnostic of a particular lithology but in some formations it is very typical and slight changes indicate subtle formation changes. The sequence illustrated (Figure 1.16) is entirely shaly: cuttings and side-wall cores find only shale. The sonic log, however, picks out small variations, probably in texture, carbonate content and quartz content, to show a very distinct stratigraphic interval despite the depth differences. It is this characteristic which makes the sonic log excellent for correlation, and even for identifying specific stratigraphic intervals, especially in fine grained sequences. There are many examples in the literature (i.e. Michelsen, 1989; Whirtaker et al., 1985).

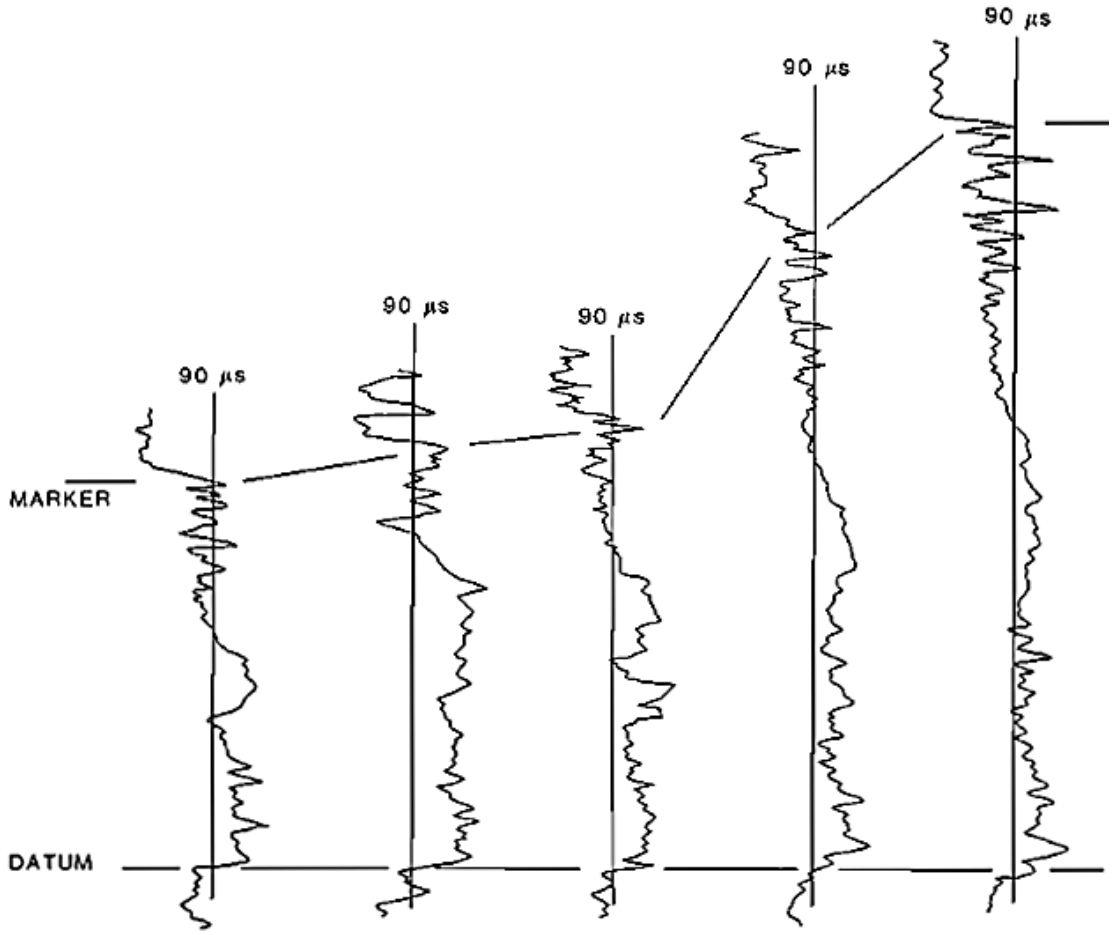


Figure 1.16 The 'character' of the sonic log used for correlation. The log is sensitive to lithological changes (texture and composition) as indicated by the logs in this shale sequence. The outside wells are 40km apart, the zone between 40m and 75m thick.

Fracture identification

A knowledge of the presumed travel paths of the sonic signals (Figure 1.7) suggests that the log may be used for fracture identification. The sonic log porosity is probably only that due to the matrix, and does not include fracture porosity. This is because the sonic pulse will follow the fastest path to the receiver and this will avoid fractures. Comparing sonic porosity to global porosity should indicate zones of fracture. The subject is fully described under the Density Log . The use of the full waveform acoustic log in fracture analysis is discussed below.

Compaction

As a sediment becomes compact, so its velocity increases. The effect is most obvious on reduced-scale sonic logs where, over thick shale intervals. there is a regular increase in velocity downwards due to compaction (Figure 1.17). In extremely homogeneous intervals when interval transit time is plotted on a logarithmic scale and depth on an arithmetic scale, there may be a straight-line relationship which represents a very regular compaction (Hottman and Johnson, 1965). Such regular relationships are especial I y visible in Tertiary sediments in many parts of the world (e.g. Herring. 1973; Magara, 1968; Issler, 1992).

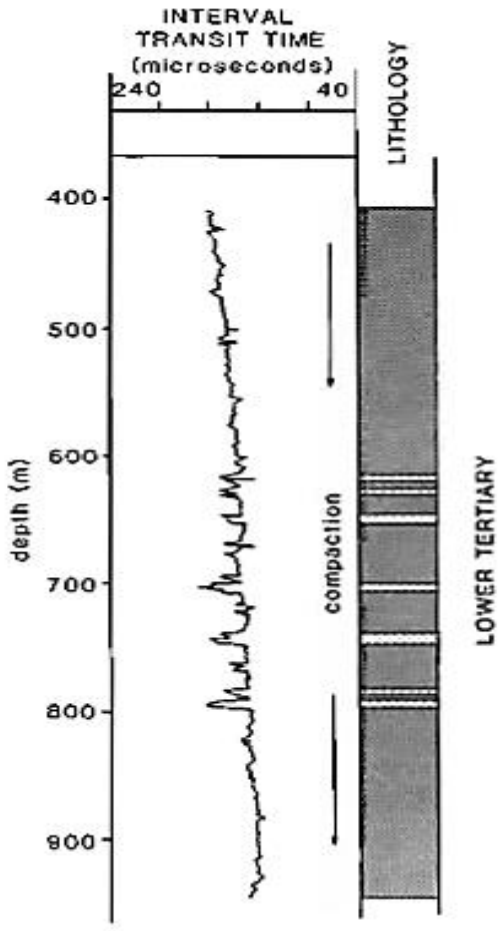


Figure 1.17 Compaction in a shale sequence shown by a regular decrease in interval transit time with depth. The velocity decreases from approximately 160µ/ft to 140µ/Ift over 500m.

But graphical methods have limitations and compaction is better studied quantitatively by measuring changes in shale porosity with depth. In turn, shale porosities can be calibrated with log derived interval transit times (Magara, 1978; Issler. 1992) (Figure 1.18). Using data from Japan and Eastern Canada. Magara (1978) proposed an empirical relationship:

$$\phi = 0.466\Delta t - 31.7$$

where ϕ = shale porosity and Δt = sonic transit time. But both the Wyllie time average equation (i.e. Bulat and Stoker, 1987. see above for the formula) and the 'acoustic formation factor' approach (Raiga-Clemenceau et al .. 1988) have been used. The latter, when used in the Beaufort-Mackenzie Basin gives the following results (Issler, 1992):

$$\phi = 1 - \left(\frac{\Delta tma}{\Delta t}\right)\frac{1}{x}$$

where ϕ = porosity, Δt = sonic log value, Δt_{ma} = matrix transit time (67μs/ft) and x = acoustic formation factor (2.19), (the figures are applicable to the Beaufort-Mackenzie Basin).

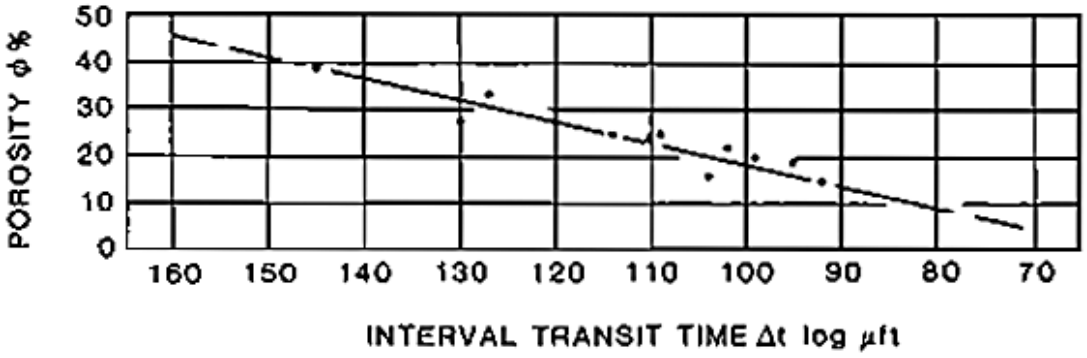


Figure 1.18 The relationship between mudstone porosity (ϕ%) and interval transit time in Miocene mudstones, Japan. (From Magara, 1968).

However, the Wyllie 'time average' and the 'acoustic formation factor' formulae were intended for sandstones, The compaction characteristics of shales and sands tones are different, shales responding essentially to physical forces, sands tones more to chemical and mineralogical agents (Magara, 1980). Thus, applying either the Wyllie formula or the acoustic formation factor is theoretically incorrect. According to Magara (1980) shales tend to compact under the general formula:

$$\phi = \phi_o \exp \frac{(-Z)}{C}$$

where ϕ = shale porosity, ϕ_o = initial porosity (i.e. 2 = 0), Z = depth of burial and C = decay constant.

Whatever relationship between shale porosity and transit time is preferred, it may be substituted in this relationship (cf. Bulat and Stoker, 1987). Using general compaction trends it is possible to estimate erosion at unconfomities or (be relative amount of uplift (Lang, 1978; Magara, 1978; Vorren et al., 1991; Hillis, 1995).

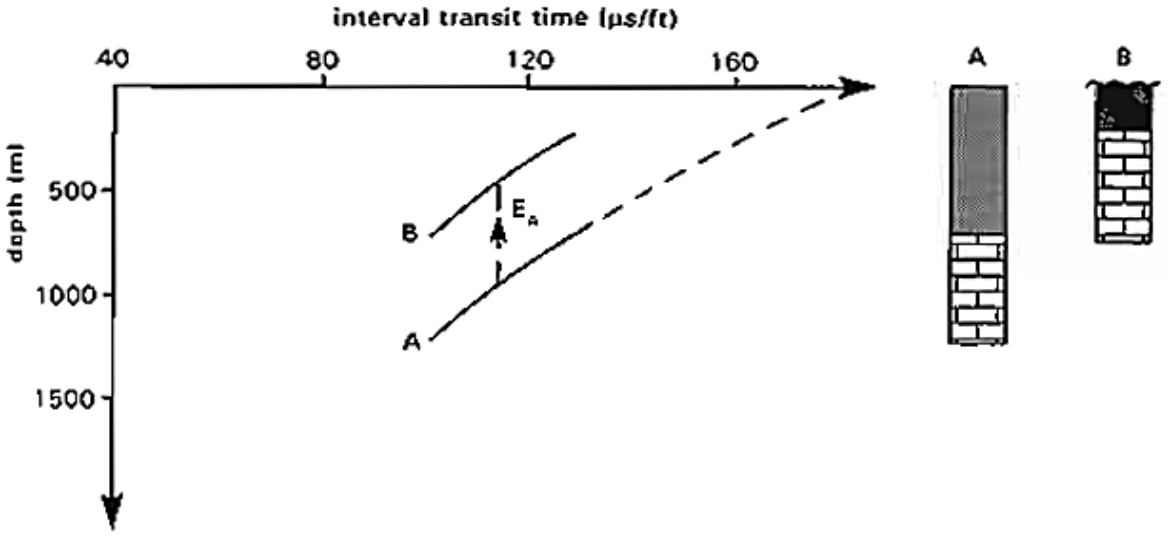


Figure 1.19 The sonic used to estimate uplift. Well A shows normal compaction (curve A). Well 8 shows 'over compaction' relative to well A at the same depth, because of uplift and subsequent erosion (curve B). The amount of uplift and erosion (Ea) is the vertical (depth) distance between curve A and curve B. Curves represent chalk compaction (re-drawn from Hillis, 1995).

pressure, it can only do so once drilling and logging are completed, by which time it may be too late!

Compaction is generally accompanied by diagenetic effects which are irreversible (e.g. Schmidt, 1973) and stay 'frozen' during uplift. The compaction of a sediment, therefore, represents its deepest burial. Using the general compaction curve for a particular interval, any 'over-compaction' can be explained by uplift. Tracking back to the general curve gives the amount of uplift (Figure 8.19). Similarly, any 'jumps' in compaction as at unconformities or faults, when compared to general well trends can give some idea of the amount of missing section. However, it should be stressed that such generalities should only be applied to one stratigraphic interval at a lime and then in a relatively consistent facies (cf. Hillis, 1995). The method has many irregularities and should be used with circumspection, but in general the sonic is the best log for compaction and uplift studies.

High-pressure identification

Acoustic velocity can be used to identify overpressure. Other things remaining constant, an increase in pore pressure or overpressure is indicated by a drop in sonic velocity. A plot of shale interval transit times through an over pressured zone shows a distinct break in the average compaction line (Figure 1.20). The principal reason for this drop is probably the increase in shale porosity, although several factors are probably compounded. It is considered possible to calculate the amount of overpressure from the extent of deviation of the sonic velocity from the normal compaction trend (Table 1.6) (Hottman and Johnson, 1965). Overpressure may also be calculated by an equivalent depth method, the simplest of which gives the following formula (Magara, 1978):

$$P = (\delta_w \times D_c) + \delta_r(D - D_c)$$

where P = formation fluid pressure at depth D (psi); δ_w = formation-water gradient (psi/ft); δ_r = lithostatic gradient (psi/ft); D = depth of calculation point (ft); D_e = equivalent depth (ft) with same sonic transit time (*see below*).

D_e is a point in the section at normal pressure which has the same interval transit time as the point being measured. An example of D and D_e equivalence is marked on the sonic-log depth plot (Figure 8.20). The above calculation suggests that the pressure at D is the sum of the hydrostatic pressure to D_e and the lithostatic pressure from D_e to D.

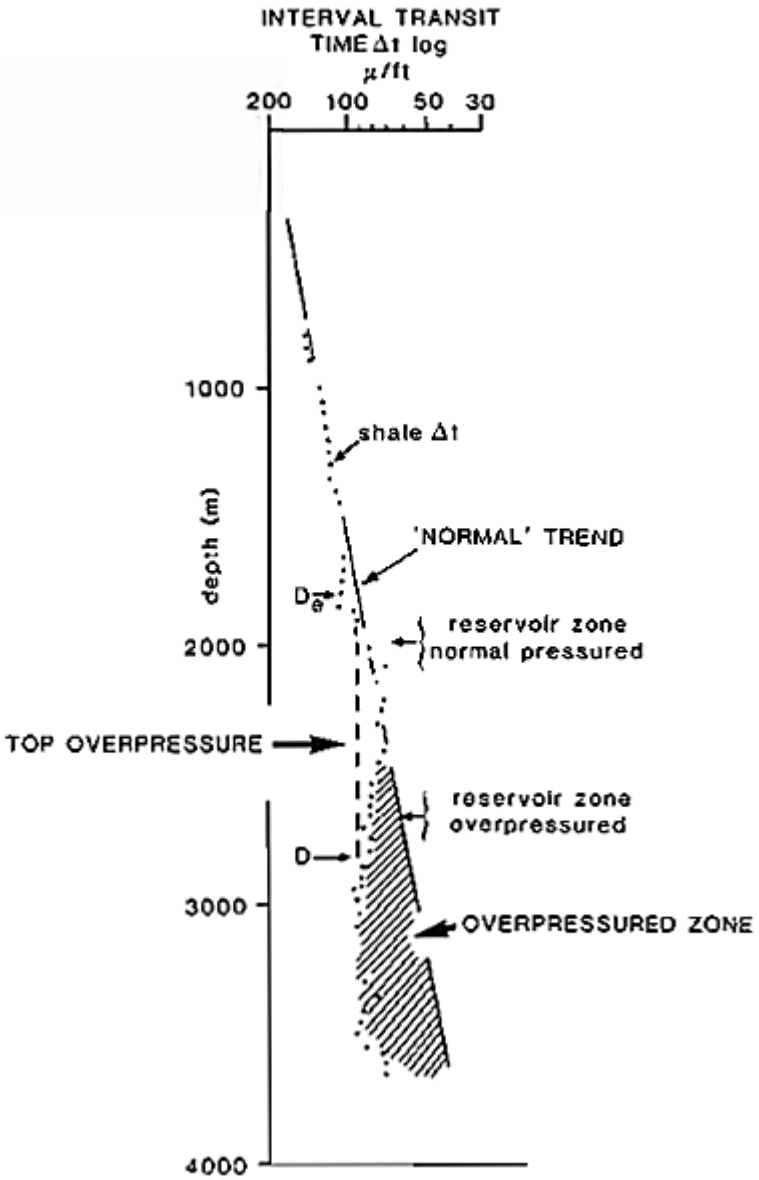


Figure 1.20 Overpressure indicated by a plot of shale interval transmit times against depth. A decrease from the normal compaction trend indicates overpressure, (D and De are for overpressure calculations).

Although the sonic log can be used to identify overpressure, it can only do so once drilling and logging are completed, by which time it may be too late!

Table 1.6 Overpressure estimates (after Hottman and J ohnson, 1965).

Dt decreases from average trends (μs)	0	20	40	60?
Reservoir fliud pressure gradient (g/cm²)	1.07	1.84	2.16	2.3?
Gradient (psi/ft)	0.465	0.800	.935	~1.00

Bore hole damage

The frequent comparison between seismic and sonic velocities has shown that there are often differences between the two which cannot be accounted for by frequency difference (Figure 1.25). The differences are thought to exist, at least partly, because sonic velocities can be affected by mechanical or chemical damage immediately around the borehole. The very shallow depth of penetration of the sonic pulse has been discussed which means that it is susceptible to immediate borehole conditions. Drilling can cause damage at the borehole wall, especially to shales either mechanically, by fracturing and spalling, or chemically by the (chemical) reaction of the drilling mud with the formation. Figure 1.21 shows the effect on the sonic measurements of progressive chemical reaction between the mud filtrate and swelling clays in a well in Colombia (Blakernan, 1982). The example is extreme since holes are not normally left uncased (Le. open) for 30-40 days. However, it does demonstrate that the phenomenon exists and that it dramatically increases the interval transit time (lowers the velocity). It means that sonic logs recorded as soon as possible after drilling will be the most representative (Blakernan, 1982).

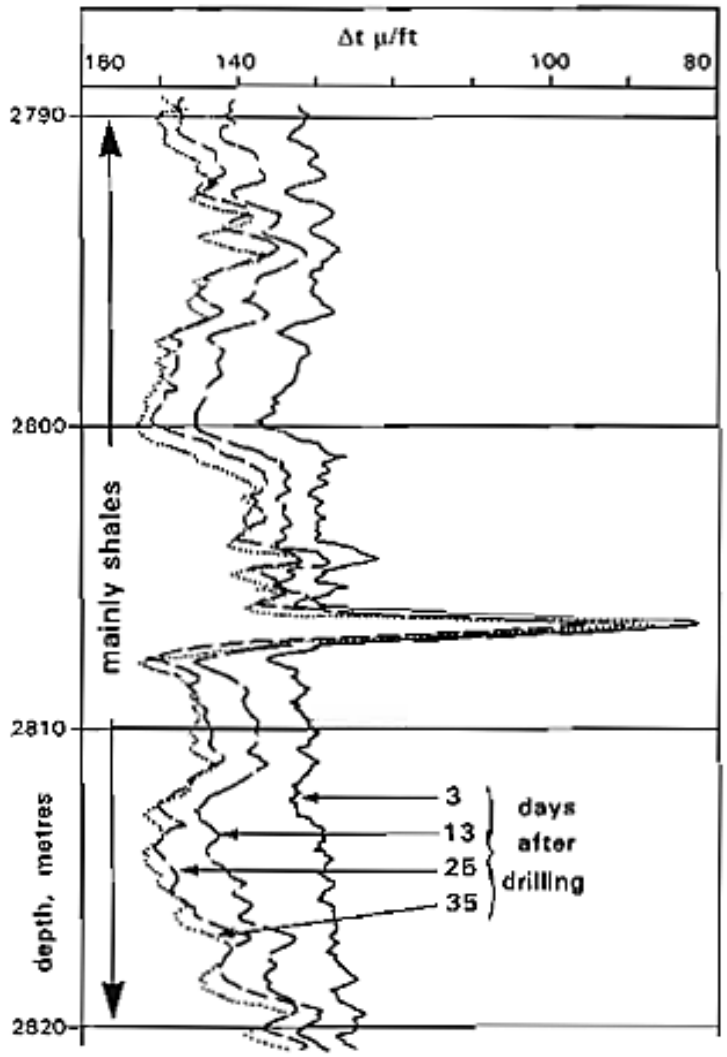


Figure 1.21 Shale alteration affecting interval transit times in a well offshore Columbia (No. I-I Punta Gallinas). Successive passes of the sonic were made over 35 days and show a persistent increase in interval transit time (decreasing velocity) indicating shale alteration and deterioration. Note there is little change in the hard band at 2807m (re-drawn from 8 lake man, 1982).

Source-rock identification

By itself, the sonic log cannot be used to indicate source rock potential. However, the presence of organic matter, especially in shales, lowers sonic velocities, apparently in direct relation to abundance and when combined with the resistivity log value the velocity is a good qualitative and possibly quantitative source indicator. Several methods of quantification exist: two are described below.

Based on an analysis of source rocks from around the world, a general formula has been derived for simply separating source from non-source rocks using a sonic resistivity combination (Meyer and Nederlof, 1984). A regression line on a sonic-resistivity cross-plot is said to separate source rocks from the non-source, both shale and limestone (Figure 1.22). The linear equation for this discriminant D, is:

$$D = -6.906 + 3.186 \log_{10} \Delta t + 0.487 \log_{10} R75°$$

where Δt = sonic log value μs/ft; R75° = log resistivity corrected to 75° F (24° C).

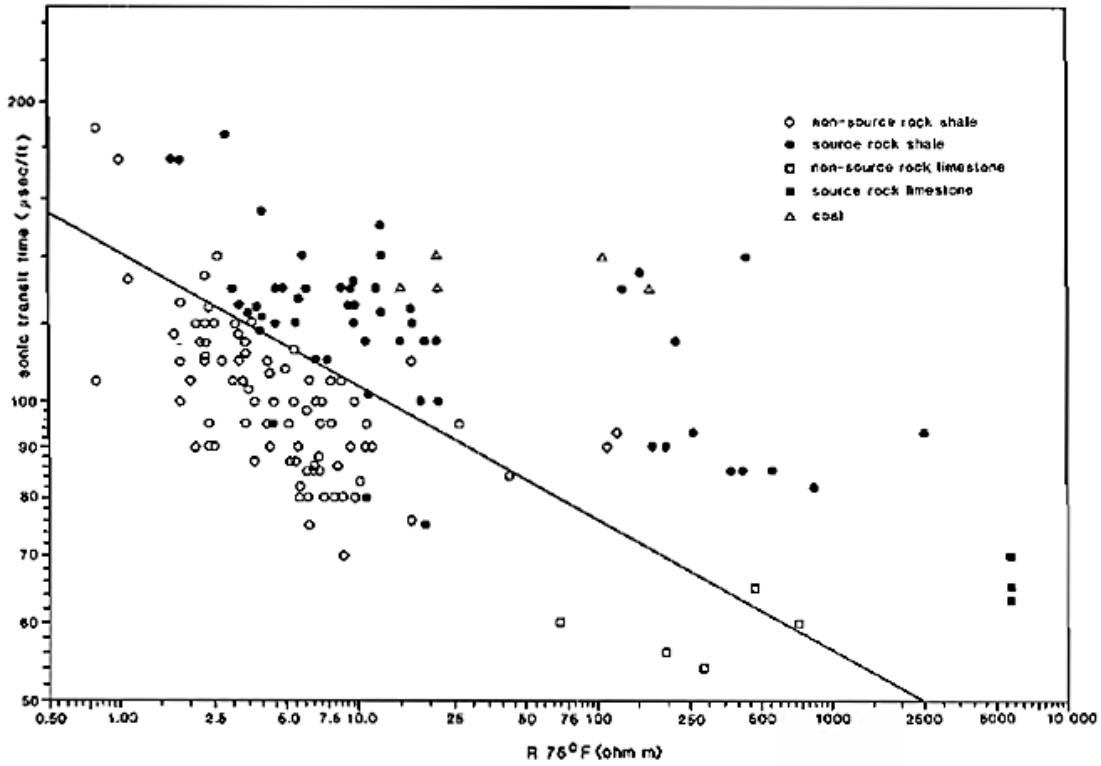


Figure 1.22 The identification of source-rock intervals on a cross-plot of resistivity against sonic transit time. The oblique line is D = 0, from discriminant analysis using points of known source-rock potential. (From Meyer and Nederlof, 1984).

A second, rather unusual, empirical method, is considered to enable actual values of TOC (total organic carbon) to be derived (passey et al., 1990). The sonic and a resistivity log are used in a standard depth plot format but the method requires two essential steps to make them 'compatible', before they can be interpreted.

First, both logs are 'scale normalized' by plotting the sank log on a scale where 50μs/ft = I logarithmic cycle on the resistivity log (for example 50μs = .01 to 0.1 ohm/m). Second, a non-source shale interval is located (in the stratigraphic interval being considered) and the two logs made to plot one on the other over that interval (Figure 8. 23). The authors call this a !:J. log R plot (Passey et al., 1990). When the two logs are plotted like this, they will track each other over all non-source shales, regardless of compaction and compositional changes. In source intervals, there will be a marked separation (Figure 1.23). There will also be a separation in hydrocarbon reservoirs and in coals but these can be eliminated on lithological grounds using, for example, the gamma ray (Figure 8.23). If the level of maturity is known, then the TOC% can be derived. The empirical equation for this is:

$$TOC\% = (\Delta \log R) \times 10^{(2.297 - 0.1688 \times LOM)}$$

where TOC% = total organic carbon in %; LOM = level of maturity (Hood et al., 1975) and 6. log R = curve separation in resistivity units.

The level of maturity must be known for the quantification since the resistivity log responds to the amount of liquid hydrocarbons in the shale pores, not the amount of solid hydrocarbon, as discussed in the chapter on the resistivity log. For example, a mature source rock is marked by a sonic low and resistivity rise; an immature source has an equally low sonic but no change in resistivity (Figure 1.23). However, that the amount of free hydrocarbon fluid in the pores of a shale is quantitatively related to the degree of maturation of the organic matter, as this method implies, remains to be proven.

This method seems to be useful qualitatively but quantitatively cumbersome and doubtfuL Moreover, as the authors point out, with just the sonic log, it is impossible to separate low sonic values due to organic matter and low sonic values due to porosity changes (such as overpressure), This is a frequent dilemma in

much log interpretation: separating the compositional effects from the textural effects. For log-based source-rock quantification, me density log appears to be simpler to use.

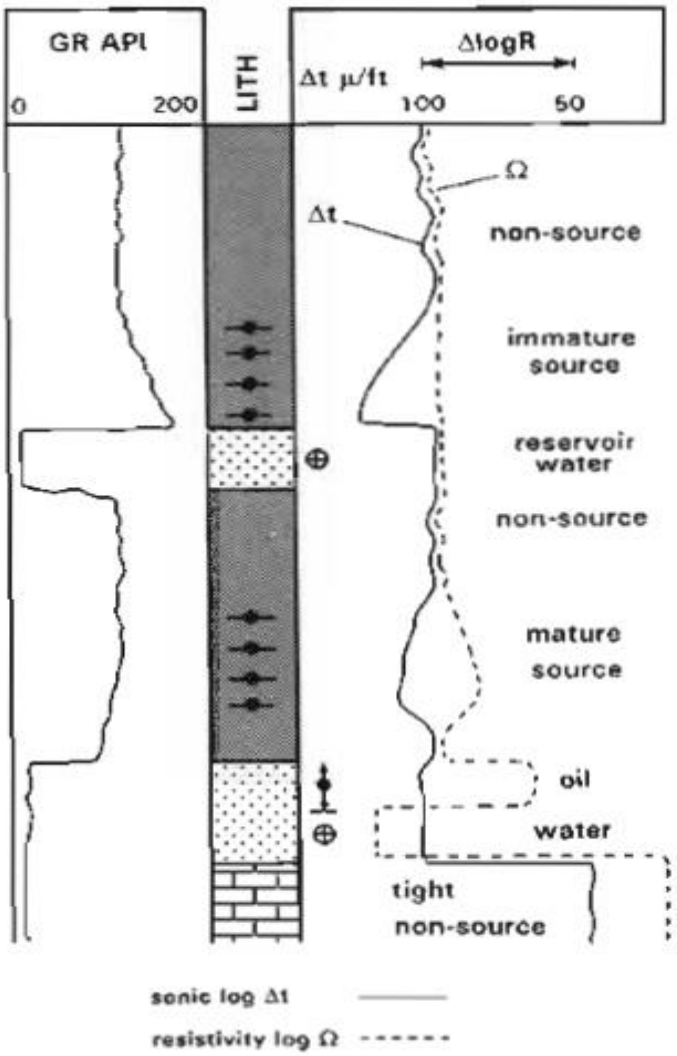


Figure 1.23 Schematic representation of sonic and resistivity log responses in source, non-source and reservoir intervals using a delta log R overlay (modified from Passey et al., 1990).