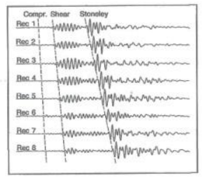
Sonic/ Acoustic Wave Logs



Introduction

In this short summary of the sonic log, the focus is on the determination of porosity. There are a number of references listed at the end of this summary, that provide excellent and more thorough examination of the underlying physics of acoustic waves, the various tools and interpretation techniques. The most recent is found in the 2007 Petroleum Engineering Handbook, Volume V(a), as given in reference 1.

The sonic log is often grouped with the neutron and density logs, as porosity logs. The tool response of all porosity logs is affected by the formation matrix, fluid and porosity. The porosity logs all have very shallow depth of investigation, usually a few inches into the formation, generally within the flushed zone.

All equations related to the sonic response are based on the fact that the reservoir rock and fluid filled pores constitute an elastic system. The sound wave that emanates from the transmitter, creates compressional and shear waves within the formation, surface waves along the borehole wall and guided waves within the fluid column.

Compressional waves (P-Waves, longitudinal waves) arrive at the receptor before the shear waves (S-Waves, transverse waves). The travel time of the compressional wave is used in calculating porosity. For further discussion on the principles of acoustic waves as related to the sonic log, see Principles.

- Properties obtained from transmitted acoustic waves

The application of the sonic log to calculate porosities evolved from experiments to better estimate of determining seismic velocities. In 1954, the Magnolia Petroleum Company introduced the continuous velocity log.

Historically, the primary use of the sonic log in reservoir engineering has been identification of porosity, cement evaluation, mechanical properties, and formation velocities for seismic studies. Digital processing and storage has opened up many more applications, as shown below.

Transmission	**Attribute**	**Property**
Compressional	Velocity	Porosity
Wave	Velocity	Lithology
	Velocity	Gas Detection
	Velocity	Rock Strength
	Velocity	Synthetic seismic
	Velocity	Geopressure Prediction
	Attenuation	Cement evaluation
Transmission		
Shear wave	Velocity	Porosity
	Velocity	Lithology
	Velocity	Rock Strength
	Velocity	Seismic Correlation, AVO, VSP
	Velocity+ Amplitude	Azimuthal anisotropy analysis
	Velocity	Rock strength determination
	Velocity	Completion design (Hydrofracture evaluation)

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- Properties from full wave form log- permeability and fracture identification

The full wave form log which records compressional, shear and Stoney waves is used to estimate in permeability and fracture identification, which can be critical to field development, reservoir management and completion interval selection. Other logs, particularly the formation microscanner can be used in conjunction with the full wave form log (also referred as the sonic array log) to identify zones of high permeability.

- Properties from Refracted Acoustic Waves

Ultrasonic reflection (pulse/ echo) acoustic devices were first introduced in 1967 with the borehole televiewer (BHTV). The transducer sends a wave pulse, which is reflected off the casing or formation, and the refracted echo wave travels back along the same path to the detector. Applications include borehole imaging, cement evaluation and casing evaluation.

Calculation of Porosity from Sonic Log

Wyllie's time averaged equation is based on a model of alternating solid and liquid layers. The model's travel time, Δt, is weighted sum based on porosities, $1 - \emptyset$ for the solid layer and $\emptyset$ for the liquid layer, with resulting equation is:

$$\emptyset = \frac{[\Delta t - \Delta t_{ma}]}{[\Delta t_f - \Delta t_{ma}]}$$

where Δt is the travel time ($\mu sec/ft$) and Δt_{ma} is the matrix travel time and Δt_f is the fluids travel time.

The velocities and corresponding travel times of the rock and matrix are:

	v_{ma} (ft/sec)	Δt_{ma} $\mu sec/ft$
Sandstone	18,000	55.5
Limestone	21,000	47.4
Dolomite	23,000	43.5
Anhydrite	20,000	50.0
Salt	15,000	66.7
Gypsum	19,000	53.0
Freshwater mud	5,300	189

The time-averaged equation, due to its simplistic model, is most suitable for clean , consolidated and compacted sandstones. The alternative, the Raymer-Hunt equation (or "field observations") results in slightly lower values of porosity for clean quartz sandstones up to about 30% porosity.

Use of Wyllie Equation in Carbonates

Calculated porosities will be underestimated in vuggy formations, since the travel times are affected most by the primary intergranular porosities. The sonic log porosities ($\emptyset_s$) can be compared to other calculated porosities (the neutron-density crossplot ($\emptyset_{nd}$ is common) and the secondary porosities due to vugs or fractures can be calculated as the secondary porositiy index (SPI), where:

$$SPI = \emptyset_{nd} - \emptyset_s.$$

The SPI is a relative indicator of fractures more than quantifying secondary porosity. The sonic log is one of a number of logs that can be used to identify natural fracturing. The most common log is the formation microscanner (FMS) log. The microspherical resistivity (MSFL) log can also be used to identify fracturing.

Uncompacted Formations with Shale Beds

The sonic log will underestimate porosity in uncompacted formations. In general, the sonic log is unsuitable for these formations and should not be used to determine porosities.

However, if only the sonic log has been run, then it is possible to correct for this underestimation, an empirical correction factor, C_p, is used, as follows:

$$\emptyset = \frac{[\Delta t - \Delta t_{ma}]}{[\Delta t_f - \Delta t_{ma}]} \cdot \left(\frac{1}{C_p}\right)$$

A number of methods are available to identify the correction factor. In uncompacted formations, adjacent shale beds will usually be over 100 $\mu sec/ft$ If shale beds are nearby, C_p can be estimated by dividing the sonic travel time in these beds (Δt_s) by 100:

$$C_p = \Delta t_s/100.$$

The compaction factor should always be greater than one. The value of C_p can also be calculated by comparing the sonic porosity to porosities calculated by other logs or neutron-density crossplot.

Raymer-Hunter Transform

The equation is entirely empirical, based on extensive field observations

$$\Delta t = \{[(1-\emptyset)^2/\Delta t_{ma}] + (\emptyset/\Delta t_f)\}^{-1},$$

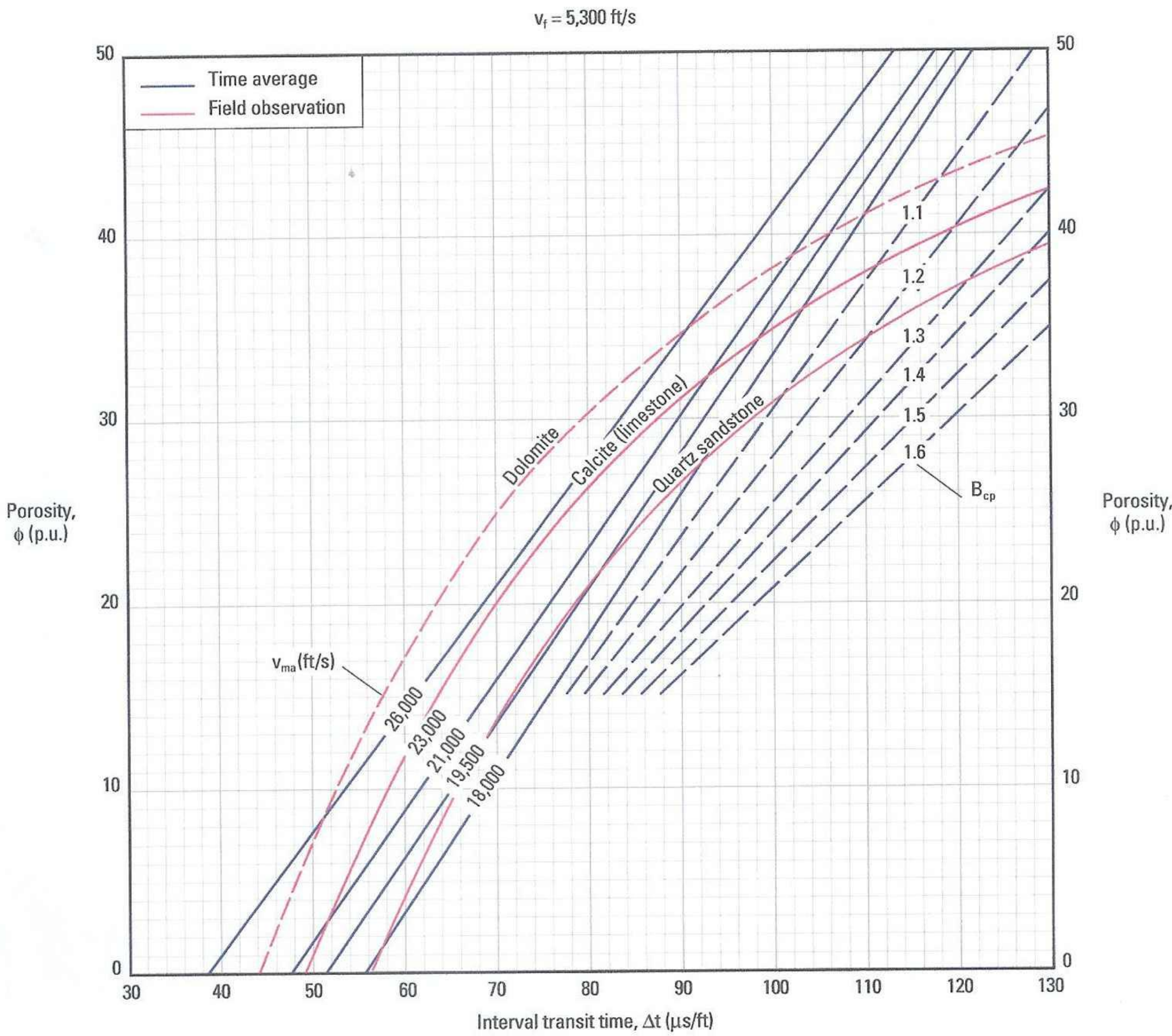
which in terms of $\emptyset$,

$$\emptyset = -\alpha - [\alpha^2 + (\Delta t_{ma}/\Delta t_{log}) - 1]^{0.5},$$

where $\alpha = \Delta t_{ma}/2\Delta t_{log} - 1$

Since the data on which the equation was based included unconsolidated sands, no empirical correction factor is required. However, the transform may result in overestimated porosities for Gulf of Mexico (see reference 2, page 57, Figure 3.22).

Comparison between Time average and field observation



Flushed zone considerations

A common assumption is that the tool readings are from the flushed zone, and for a fresh water mud, corresponding to $\Delta t_f = 189\ \mu sec/ft$. The more compressible fluids, gas and oil, will result in lower velocities and thus higher travel times. Using the fresh mud value of $\Delta t_f = 189\ \mu sec/ft$ results in an over estimation of porosity, so the porosity can be scaled back to account for this. Commonly used porosity correction factors are 0.90 in oil zones and 0.70 in gas zones. (Reference 1)

Tool and Environmental Considerations

Acoustic waves not only move through the formation, but the mud system as well. The dual receiver system was developed to remove the mud path contribution from the response of the sonic tool. Modern tool (beginning in the 1960's) used two transmitters and two receivers to compensate for hole rugosity and tool tilt.

Velocity measurements can be affected to a variety of factors in the borehole, such as signal noise, cycle skipping, gas effect and dip angle with respect to the borehole, however better microprocessing has eliminated these affects.

- Long Spaced Sonic Tool

As stated in the introduction, typically acoustic logs measure only the flushed zone. Well bore washouts may prevent obtaining reliable data in these cases. Long spaced tools use an asymmetric arrangement of configuration of transmitters and receivers, requiring a different method to calculate borehole compensation (Depth derived bore hole compensation or DDBHC). See discussion of on page V-178 in Reference 1.

- Full Waveform Sonic Log

The full waveform sonic log records the entire wave form from a series of receivers. The intent is to identify zones of improved permeability and fracturing. The waveform sonic log provides full recording of the compressional, shear and Stoney waves.

The full waveform and NMR logs to interpret permeability and zones of fracturing, extends the ability of logs be used in conjunction with other measurements (core analyses and pressure testing) to describe flow characteristics.

Other Applications

The sonic can be used as a LWD log, and we intend to update this discussion soon. Lithology determination (M-N, Mid Plots) will be reviewed in a separate discussion. A number of additional applications will be included in the future: cement bond log, mechanical properties and borehole imaging.

References:

1) Patterson, D. and Prensky, S., Petroleum Engineering and Petrophysics, Volume V(a), Chapter 3C, from the Petroleum Engineering Handbook, Editor, Edward Holstein, 2007.

2) Bassiouni, Z.,Theory, Measurement and Interpretation of Well Logs, SPE Textbook Volume 4, 1994,

3) Log Interpretation Principles/ Applications, Schlumberger, 1991 (also charts from their website).