Seismic anisotropy in sedimentary rocks

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Summary

A single-plug method for measuring seismic velocities and transverse isotropy in rocks has been designed and rigorously tested. It reduces the total time by more than two-thirds (2/3) for preparing core samples and measuring velocities in transversely isotropic rocks.

Many sedimentary rock samples including shales, coals, sands, sandstones, and carbonates have been measured using this method. The results show that clays and fine layering in sedimentary rocks are the main causes of seismic anisotropy. Very little seismic anisotropy exists in reservoir rocks like sands, sandstones, and carbonates under reservoir conditions. On the other hand, all shales are seismically anisotropic. At present, the degree of shale anisotropy cannot be accurately predicted from other data without laboratory measurements. This paper also presents some best practices for laboratory measurements of shale anisotropy.

Introduction

Figure 1 shows the compressional (Fig. 1a) and shear (Fig. 1b) velocities measured in a West Africa shale versus time and pore pressure. The core was from a depth of 6000 ft (1829 m) and preserved inside a PVC barrel filled with epoxy. It had approximately 10 percent porosity. The overburden pressure was fixed at 41.4 MPa (6000 psi) during measurements, which is approximately equivalent to the in-situ overburden pressure. The initial pore pressure was 34.5 MPa (5000 psi) and as time went on, was decreased to 27.6 MPa (4000 psi), 20.7 MPa (3000 psi), and 6.9 MPa (1000 psi) successively. Above the in-situ pore pressure (approximately 19 MPa or 2750 psi), the pore pressure equilibrated reasonably fast and the velocities stabilized accordingly. However, when the pore pressure was decreased from 20.7 MPa (3000 psi) to 6.9 MPa (1000 psi), the shale started to compact because the net pressure (overburden pressure minus pore pressure, also called differential pressure) went beyond the in-situ value. The compaction lasted over eight weeks during which all the five velocities (three compressional and two shear) continued to increase.

The data shown in Figures 1a and 1b were collected using the single-plug TI velocity measurement method. It clearly illustrates that it can be extremely time consuming to measure seismic velocities in shales in the laboratory and that velocity data collected under other than the original in-situ stress and saturation conditions may be suspect.

Laboratory Anisotropy Measurements - the Single-plug Method

To overcome the difficulties in measuring elastic properties of TI materials, we designed a single-plug method in which four P-wave transducers (2 transmitters and 2 receivers) are built into the confining plastic jacket. Instead of cutting three adjacent core plugs, this method uses a single horizontal (90^o to the symmetry axis) core plug (Figure 2). In this method, the horizontal and 45^o P-wave transducers have to be sealed into the plastic jacket. The transducers have to be small enough to accommodate the plug sample size (51 mm diameter) but big enough to avoid being point transmitters and receivers (point sources are actually acceptable in laboratory measurements but plain waves are preferred so that no correction for geometrical spreading is needed for attenuation calculations). The transducer surfaces must be curved to fit the sample perfectly to transmit the waves efficiently. Great care must be taken to prevent leakage of the confining hydraulic oil into the core plug. The transducers must be aligned as well as possible to limit the measurement error.

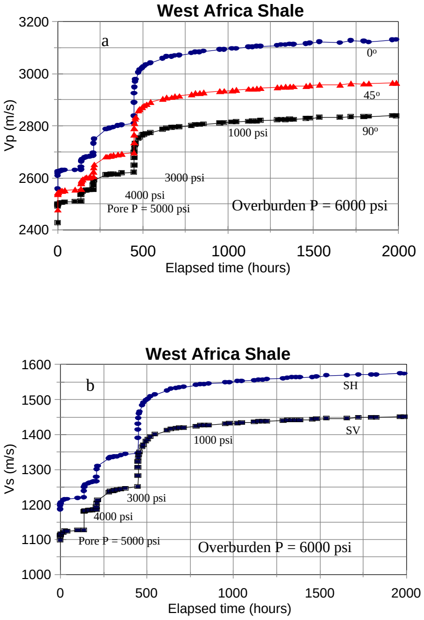

Figure 1. Compressional (a) and shear (b) velocities measured in a brine-saturated West Africa shale as a function of time. The overburden pressure is kept at a constant 41.4 MPa (6000 psi) throughout the experiment, whereas the pore pressure changes from 34.5 MPa to 27.6, 20.7, and 6.9 MPa successively (from 5000 psi to 4000, 3000, and 1000 psi).

The top-bottom transducer assembly (either top or bottom) consists of three individual transducers: one P and two orthogonally polarized S transducers. The measured velocities, along with the bulk density, yield the elastic constants C_{11}, C_{44}, and C_{66}. The side horizontal P-wave transducers (one transmitter and one receiver), aligned along the direction of the symmetry axis (perpendicular to bedding), yield C_{33}. The side 45° P-wave transducers are aligned 45° to the symmetry axis (45° to bedding) that yield C_{13}.

When measuring velocities in a non-horizontal core plug, special care has to be taken to align the transducers so that the top transducers are measuring $V_{p\theta}$, $V_{sv\theta}$, $V_{sh\theta}$ and the side horizontal transducers are measuring $V_{p(90^o-\theta)}$, where θ is the angle between the sample axis and the symmetry axis (for a perfectly horizontal core plug, $\theta = 90^o$). In this case, the side horizontal 45° transducers are measuring $V_{p\phi}$, where $\phi=\cos^{-1}(\sin\theta \sin 45^o)$.

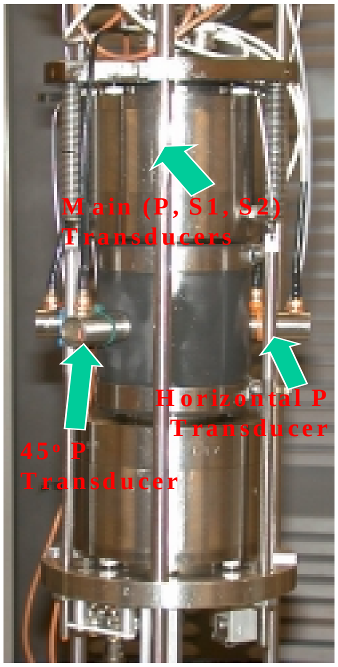

Figure 2. Illustration of the single-plug method for anisotropy measurements. A parallel plug (plug axis is perpendicular to the symmetry axis) is used here but not required. The top or bottom transducer assembly consists of one P- and two orthogonally polarized S-transducers. The side transducers, one aligned along and one aligned 45° to the symmetry axis, are built inside the sealing jacket.

Laboratory Results

We have measured seismic anisotropy (transverse isotropy) in many reservoir and non-reservoir rock samples during the past several years. This paper contains the results of 17 brine-saturated shale samples, one gas- and brine-saturated coal sample, eight brine-saturated sands, 12 gas-saturated sands, 32 gas-saturated carbonate samples, and 25 brine-saturated carbonate samples.

P- and S-wave anisotropies ε and γ (Thomsen, 1986) are also calculated using:

$$\varepsilon = \frac{C_{11} - C_{33}}{2C_{33}}, \tag{1}$$

$$\gamma = \frac{C_{66} - C_{44}}{2C_{44}}, \tag{2}$$

where the elastic constants C_{11}, C_{33}, C_{44}, and C_{66} were derived from the measured velocities and bulk density.

Shales and Coal.. All the measured shale and coal samples are anisotropic. Anisotropy in shales ranges from 6% to 33% for P-waves (ε) and 2% to 55% for S-waves (γ). Strictly speaking, the siliceous shale is diatomite, not actual shale. As such, the siliceous shale samples exhibit only a small degree of anisotropy. The coal sample is extremely anisotropic, showing over 40% anisotropy for both P- and S-waves.

Sands. In general, reservoir sands and sandstones are intrinsically isotropic unless they are fractured, finely layered, or clay-bearing. The results show that the brine-saturated reservoir sands, which are essentially clay-free, have very little anisotropy. The average -0.6% P-anisotropy and -1.1% S-anisotropy are probably within the measurement uncertainties. For the brine-saturated tight sands, the anisotropy is 5.0% for the P-wave and 3.3% for the S-wave when averaged over all samples at all pressures. At the net reservoir pressure of 7500 psi (51.7 MPa), anisotropy is slightly lower, averaging 4.6% and 3.2% for P- and S-waves, respectively.

The gas-saturated tight sands and shaly sands all show some degree of anisotropy, ranging from 0% to 36% for P-wave and 0.3% to 19.5% for S-wave. When averaged over all the tight sand and shaly sand samples at all pressures, the anisotropy is 9.9% for the P-wave and 5.5% for the S-wave.

The shaly sands all exhibit higher anisotropy at low net pressures. Because these shaly sand samples were not preserved and allowed to dry, the samples might have developed microfractures along the bedding plane. As a result, anisotropy is greatly amplified at low net pressures. At a net pressure of 500 psi (3.5 MPa), the average anisotropy is 20.3% for the P-wave and 11.2% for the S-wave. High net pressures tend to close these microfractures so that anisotropy decreases. At a net pressure of 3000 psi (20.7 MPa), the average anisotropy is only 3.7% for the P-wave and 2.5% for the S-wave. This illustrates the great importance of preserving shale and shaly sand cores for correct measurements of seismic velocities and anisotropy in the laboratory.

Carbonates. We have measured 32 carbonate samples from Canada and the Gulf Coast using our single-plug anisotropy apparatus. The samples include 25 limestone samples, most of which are very tight, and 7 dolomite samples. The velocities were measured at eight pressure points from 1000 psi (6.9 MPa) to 8000 psi (55.2 MPa) with 1000 psi (6.9 MPa) increment.

The dolomite samples are essentially isotropic, especially at high net pressures. The tight limestone samples also show very little intrinsic anisotropy, except two samples with stylolites. In gas-saturated carbonates, anisotropy averages at 2.9% for the P-wave and 1.3% for the S-wave. When the samples are saturated with brine, the average P-wave anisotropy decreases to 1.7%, whereas the S-wave anisotropy remains nearly unchanged. We first expected by visual inspection that the tight limestones would be intrinsically anisotropic. It turns out that intrinsic anisotropy is insignificant in carbonate rocks, especially under high in-situ pressures.

Discussion and Analysis

Anisotropy Relations. Figure 3a shows that a linear relationship exists between P- and S-wave anisotropies. In general, P-wave anisotropy is slightly higher than S-wave anisotropy for a given rock with a few exceptions. A total of 259 data points are plotted in Figure 3a. The dashed line represents a one-to-one relationship between P- and S-wave anisotropies, whereas the solid line is the best fit to the data:

$$\gamma = -0.01049 + 0.9560\,\varepsilon \quad \text{with } R^2 = 0.7463, \qquad (3)$$

where γ and ε are the S- and P-wave anisotropy, respectively, defined in equations (5) and (6). R^2 is the correlation coefficient.

Equation (3) shows that S-wave anisotropy may be estimated from P-wave anisotropy, or vise versa. Such estimation is independent of pressure, pore fluids, and lithology. It is particularly useful when S-wave anisotropy is available but P-wave anisotropy is not. In this case, P-wave anisotropy can be derived from equation (3) and used in seismic imaging.

Figure 3b shows the relationship between ε and δ. The sand and carbonate samples show essentially $\varepsilon \approx \delta$, whereas most shales show $\varepsilon > \delta$. This means that sands and carbonates, if anisotropic, will most likely possess elliptical anisotropy.

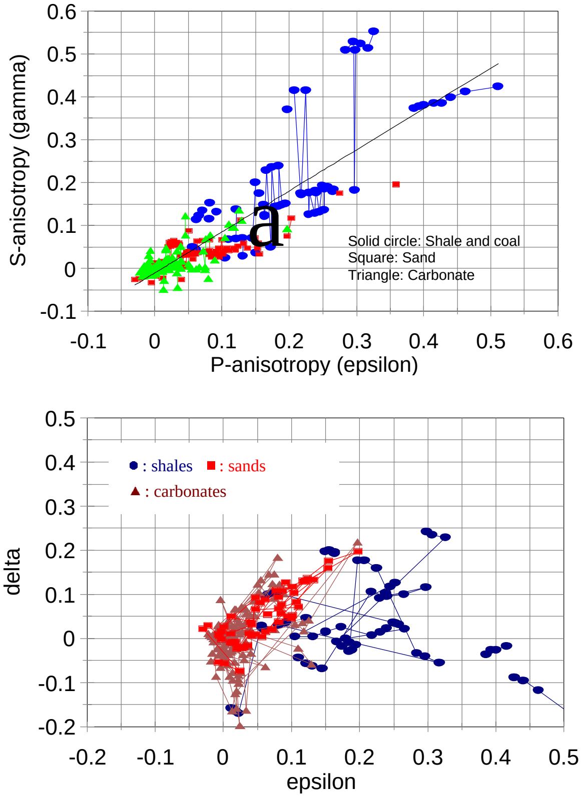

Figure 3. Relationships between ε and γ (a) and between δ and ε (b). The solid line in (a) is the best-fit to the data. The dashed gray lines corresponds to one-to-one relationships between ε and γ and between δ and ε.

Effect of Porosity

Anisotropy in sands and carbonates is not directly affected by porosity. Instead, it is more affected by the texture (fractures, cracks, lamination) and clay content. For shales, anisotropy is affected by porosity because high porosity, young shales tend to be less laminated. As shales are compacted, porosity decreases and clay platelets are preferentially oriented. As a result, anisotropy increases.

Figures 4a and 4b show that the magnitude of anisotropy seems to decrease exponentially in shales as porosity (ϕ) increases. The solid lines are the best fit to the data:

$$\varepsilon = 0.35486\, e^{-7.417\phi} \qquad (4)$$

$$\gamma = 0.43461\, e^{-10.304\phi}, \qquad (5)$$

where ϕ, ε, and γ are all in fractions.

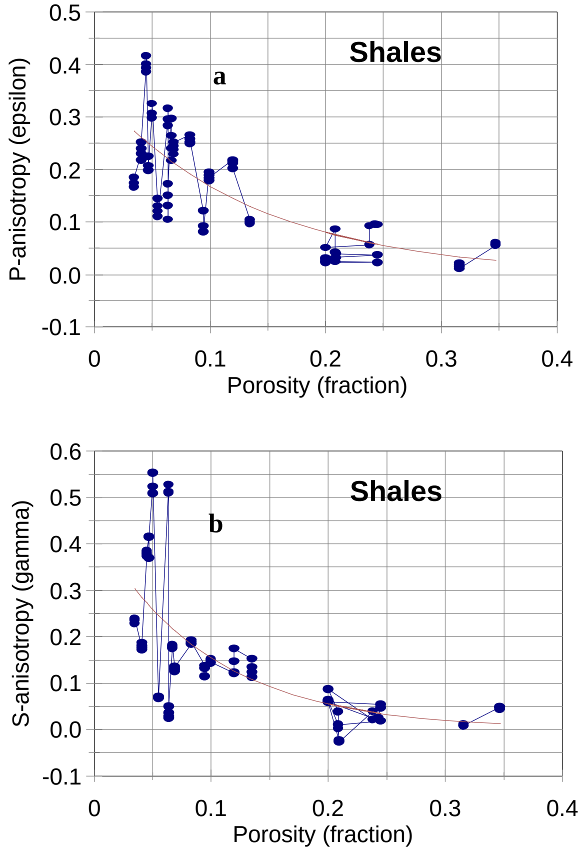

Figure 4. Anisotropy parameters ε (a) and γ (b) versus porosity. The solid lines in (a) and (b) are the best-fit to the data. Although large scatter exists, both P- and S-wave anisotropies seem to decrease exponentially with increasing porosity.

Equations (4) and (5) provide a means of estimating seismic anisotropy from porosity in shales. When real data are unavailable, they can be used to estimate seismic anisotropy in shales for various applications.

Effect of Pressure

Increasing net pressure tends to close microcracks and put the rock grains in better contact. As a result, seismic anisotropy is expected to decrease as net pressure increases. Almost all the measured shales show anisotropy decreases as the net overburden pressure increases. This is in general true for deeply buried shales (say, depth > 1000 ft or 300 m). For shallow clay-rich sediments, such as seafloor or lake-bottom sediments, anisotropy may increase as the net overburden pressure increases. Because these sediments have never been under pressure to compact, the clay platelets in the sediments may be poorly aligned or even randomly oriented. Compaction presses and orients the clay platelets to their most mechanically stable condition in which the platelets are stacked together and aligned, resulting in higher magnitude of anisotropy.

Best Practices

Through many years of experience in measuring shales and anisotropy, we have learned some lessons and established some best practices. They are listed as follows:

Coring and core preservation. Shale cores should be preserved. Normally, the core is encased in a PVC pipe and sealed with epoxy at the well site to prevent fluid loss. The best way to preserve a shale core is through pressure coring so that it is stored under the in-situ pressure. However, pressure coring and storing is too expensive so that PVC pipe preservation is a good alternative. The core should not be frozen at any point because the volume change of water to ice will damage the internal structure of the core.

Core preparation. Core plugs should be carefully drilled from the preserved core at a low speed. A compatible brine, preferably the original in-situ fluid or oil, should be used as the drilling coolant. The end faces of the plugs are then prepared inside the cooling fluid to be parallel and flat. During preparation, one must make sure not to dry the sample.

A dry shale? Dry shales don't normally exist in nature because clays always absorb water. As a result, shale samples should **never** be dried in the laboratory or in storage. A dried shale sample will crack or fracture and loose its integrity. Even if after restoring pore fluid at pressure, the shale may be still permanently damaged.

Laboratory measurements at in-situ stress conditions. The in-situ stress condition (overburden and pore pressures) should be determined and the shale sample should be pre-stressed at the in-situ level for at least 48 hours before velocity and anisotropy measurements. All anisotropy measurements must be performed at in-situ saturation and stress conditions. Caution should be taken not to over-stress the shale. As shown in Figure 1, consolidation of the shale sample will take place once the net pressure exceeds the in-situ value, resulting in continuous velocity increases over a long period of time.

Laboratory measurements at in-situ temperature and saturation conditions. Velocities and anisotropy of shales are only slightly dependent on reservoir temperature. As a result, laboratory measurements may be performed at room temperature if equipment capability is limited to low temperatures. However, the shale sample must be measured at in-situ saturation conditions, i.e., it should be saturated with an in-situ brine at the in-situ saturation level (normally full brine saturation).

Conclusions

A single-plug method for measuring acoustic velocities and transverse isotropy in rocks has been developed. This method has been rigorously tested and proven to save at least two-thirds (2/3) of the time for preparing core samples and measuring velocities in transversely isotropic rocks. Using this method, all the measurements can be performed under in-situ reservoir conditions (pressure, temperature, and fluid saturation). It is particularly suitable for measuring shales with low permeabilities.

Our data show that essentially all shales are seismically anisotropic. As such, anisotropy can not be ignored in seismic processing and interpretation, especially when the shale layers are thick. For processing and interpretation using near offset gathers (incident angle less than 20^o), the anisotropy effect is relatively insignificant. However, for far offset seismic processing and interpretation, seismic images may be greatly distorted and AVO effects may be erroneous if isotropy is assumed.

Shale cores must be preserved. Once a shale core is dehydrated, fractures will develop along the bedding plane and the measured seismic velocities and anisotropy will no longer be accurate. Because fractures magnify the magnitude of anisotropy, dry shales or previously dried, re-saturated shales will show abnormally high degrees of anisotropy.

Intrinsic anisotropy is insignificant in reservoir rocks such as carbonates and massive sands. The average measured anisotropy over many reservoir rocks is around two percent, which may be within the uncertainty range in field applications. However, tight sands, shaly sands, siltstones, or thin sand-shale sequences may be seismically anisotropic. The anisotropy may exceed 10% in these rocks.

Acknowledgment

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References

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