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C-Wave Data Improve Seismic Imaging

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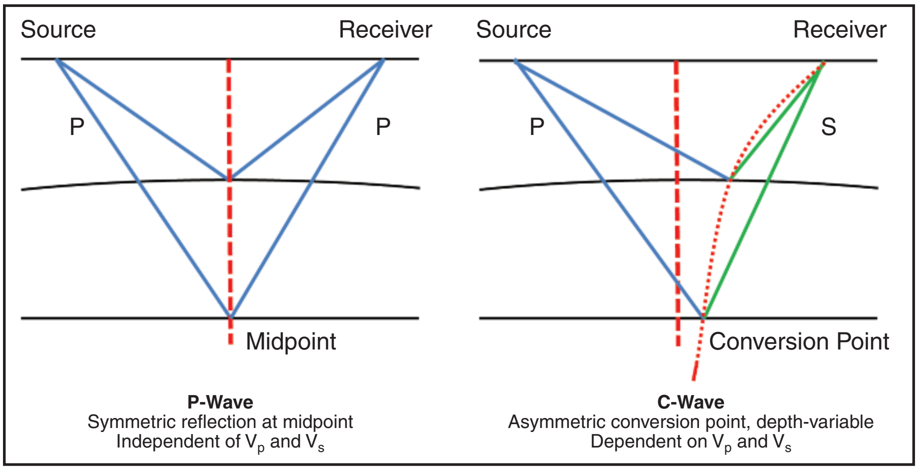
HOUSTON–Conventional compressional (P)-wave seismic data have been a mainstay for the search and production of hydrocarbons for many years. P-wave data allow geoscientists to generate structural maps of the subsurface to delineate potential hydrocarbon traps.

Through detailed amplitude studies, conventional P-wave data also provide subsurface attributes that allow the identification of subsurface lithologies, and under appropriate conditions, can confirm the presence, phase and extent of hydrocarbons. However, there are some seismic imaging problems that cannot be resolved by P-waves alone, but that require the use of shear (S) waves.

There are two types of shear-wave surveys that can be carried out. In the first type, shear-wave sources can be used to directly excite shear waves and observe their reflections back to the surface, in an analogous manner to a P-wave survey. However shear-wave sources are difficult to obtain and manage.

FIGURE 1

P-Wave versus C-Wave Ray Paths



While land shear vibrators do exist, they are very few in number and very hard to operate and maintain. In the marine environment, because fluids such as seawater do not support shear waves, shear sources are essentially nonexistent.

For that reason, shear-wave data are usually collected by using a P-wave source, but also through recording energy from a P-wave that travels down from the source as a P-wave, undergoes a mode-conversion at an interface, and returns to the receiver as a shear wave. Shear waves that have been generated by the conversion of a P-wave in the subsurface are called "converted waves" (C-waves). They also are referred to as PS-waves.

The critical difference between P- and C-waves is the direction of particle motion. A P-wave has its particle motion along its direction of propagation. The C-wave reflected back has its particle motion perpendicular to its propagation direction. Therefore, the only way that this type of conversion can occur is if the incident P-wave strikes the interface at an oblique angle.

To record reflected C-waves, one must use multicomponent receivers detecting particle motion in the vertical and horizontal directions, giving rise to the name "multicomponent seismic" for surveys collected in that manner. The addition of converted-wave data allows the geoscientist to paint a richer and more revealing portrait of the subsurface, as shear-wave properties of subsurface layers can be directly measured along with P-wave properties.

Figure 1 shows P-wave versus C-wave ray paths. The thin vertical red dotted line on the C-wave image (right) is the asymptotic conversion point, which is the conversion point location at infinite depth/time. Vp denotes the P-wave or compressional-wave velocity in the formation, while Vs denotes the shear-wave velocity. Ray paths where P-waves travel downward and reflect upward off of an interface are referred to as PP-data (left figure), whereas ray paths with a downgoing P-wave and an upgoing S-wave are referred to as PS-data (right figure).

One of the most significant differences between P-waves and shear waves has to do with fluids: While P-waves do propagate in fluids (you can sing underwater in a pool!), fluids do not support shear waves. In the rest of this article, we discuss the different ways in which the use of shear waves in the form of converted waves can help in the exploration, drilling and production process.

The application of shear waves is naturally broken into "conventional" and "unconventional" plays. By conventional plays, we mean hydrocarbons that are trapped in reservoirs with sufficient permeability that wells often (but not always) will flow to the surface without assistance. By unconventional plays, we mean hydrocarbons that are present in rocks that are not commonly seen as reservoirs, such as shales or very tight gas sands, and that necessitate artificial permeability generation through hydraulic fracturing or some other means.

In addition to the "reservoir," the two types of plays differ radically in the trap style or even presence. A reasonably well-defined trap is present in conventional reservoirs, whereas unconventional reservoirs have a ubiquitous, but variable pres-

FIGURE 2

Classic Gas Cloud Effect (PP Image versus PS Image)

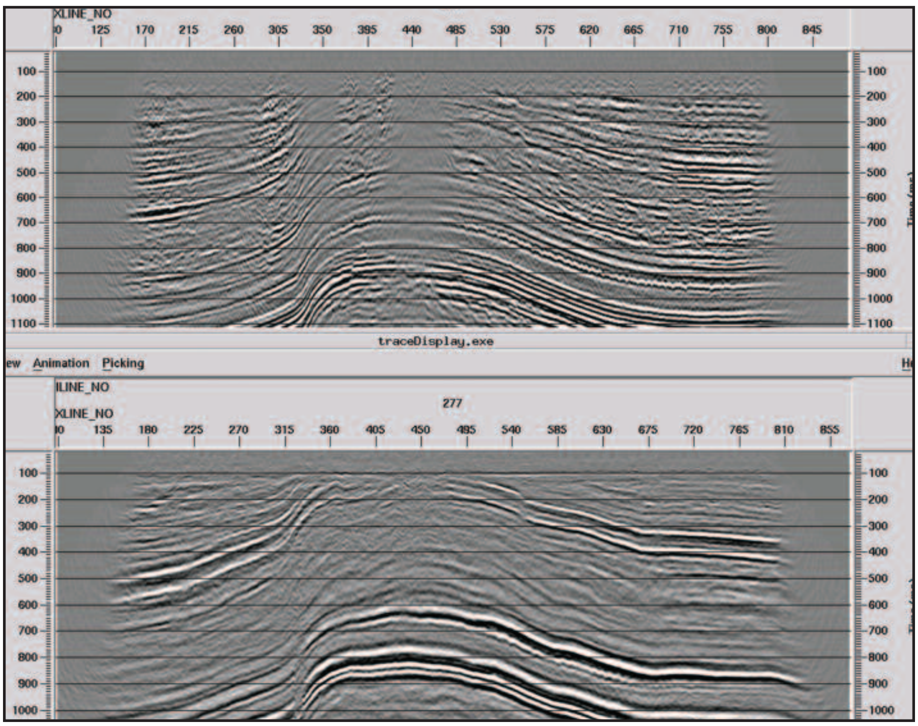


FIGURE 3

P-Wave Stack Amplitudes (Top) versus C-Wave Stack Amplitudes (Bottom)

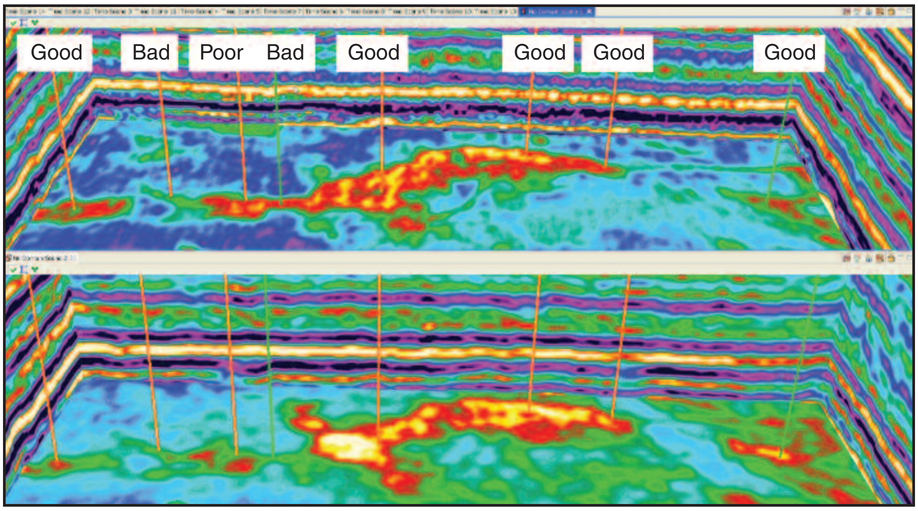


Image courtesy of Apache Corporation

ence over wide areas. Clearly, the information that shear waves will bring to these types of plays will be different.

Conventional Plays

The primary use of converted waves has been to image through gas clouds, usually using multicomponent ocean-bottom cable data. A gas cloud is a low saturation accumulation of gas usually above a deeper reservoir, or resulting from a breached trap. Gas clouds are common in both the North Sea and the Gulf of Mexico. The properties of P-waves are controlled by both elastic rock properties and pore fluid properties.

One can think of P-waves simply as compressing a sponge (the rock) filled with either pure water or water with partial gas saturation. It is clearly easier to compress a sponge containing a fluid with gas dissolved. As a consequence, the presence of even low gas concentrations can dramatically slow P-waves and attenuate them. In contrast, shear waves are only sensitive to the rock matrix, so they are able to propagate relatively unperturbed through rocks with different fluids, such as gas-charged zones.

The data shown in Figure 2 provide a classic example of imaging problems in an area where the presence of gas has created a P-wave shadow zone, or "holes," caused by the presence of a gas cloud that attenuates the P-waves (upper image). Because shear waves are not susceptible to the presence of the gas and are able to propagate unattenuated through the gas cloud, reflector continuity is improved above the anticline (lower image). Also nicely imaged in the shear-wave section is a shallow unconformity at around 100 milliseconds on the top of the anticline.

Converted-waves provide a more direct measure of shear impedance than standard indirect approaches using P-wave inversion. Where shear impedance allows discrimination of lithology, C-wave stack amplitude can be an effective predictor of well productivity. In Figure 3, the top section view shows P-wave stack amplitudes extracted at the target horizon. The bottom section shows the equivalent C-wave stack amplitudes. Higher amplitudes are represented by warm colors. The C-wave data prove to be a more effective predictor of well productivity, as indicated by the labels "good" or "bad" at the well locations. Although the correlation is empirical, it is likely that such improved correlations exist because of C-wave's greater sensitivity to lithology, thus yielding more accurate impedances.

P-wave data are used for amplitude versus offset/angle analysis of fluid indicators, as well as the more technically sophisticated prestack simultaneous inversion of PP angle-gathers. These processes produce estimates of acoustic and shear impedance. It is well documented that these techniques help derisk the presence and phase of hydrocarbons in conventional 3-D P-wave data. However, getting reliable density information from conventional P-wave seismic data is difficult at best. While technically possible by using very long offset data, those data usually are contaminated with imaging errors from processing or from anisotropy.

Usually, conventional data only allow us to determine the impedances of rocks in the subsurface, namely the product of velocity and density for both P- and S-waves. Incorporating PS data into the workflow requires good-quality PS data, and good processing and registration of P and S data. But the joint inversion of PP and PS data leads to better acoustic and shear impedance results, and at the same time, much improved density estimates.

This principle is illustrated with two data illustrations. Figure 4 shows the results of inverting for density using PP data only (red line) and by using PP and PS data simultaneously (green line), compared with a density well log. The light gray curve is a density log at full resolution, and the black curve is the same log upscaled to seismic resolution. Clearly, adding the PS data helps. Although not a perfect match, the green line more faithfully represents the excursions of the real density curve than the red curve.

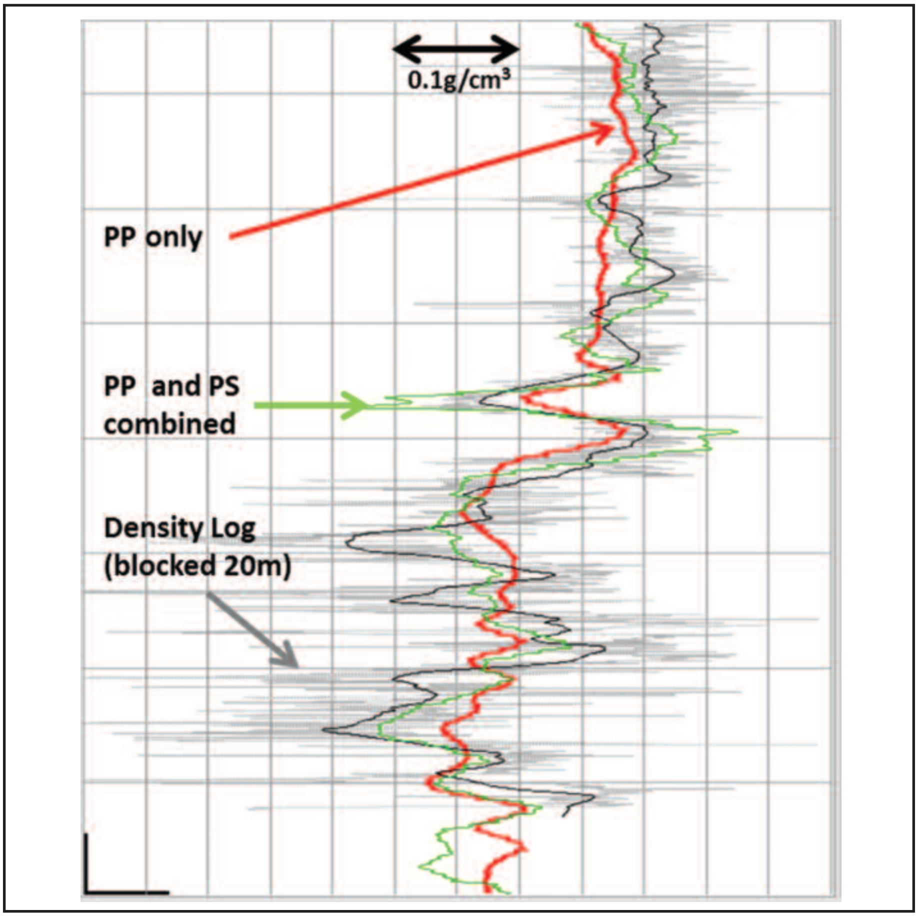
Figure 5 demonstrates that the combination of P and C data offers a considerably more robust measurement of rock properties than inversion of the individual data types. In this 3-D cube through data inverted for lithology, P-wave data are shown on the left with C-wave data on the right. Note the crisper appearance of the section on the right, showing the greater sensitivity of shear waves to lithology variations.

Unconventional Plays

Unconventional resource plays involve developing reservoirs with very low natural permeability, such as shales or tight sands. Because of the low permeability, these formations will not produce naturally and require the creation of permeability pathways into the rock matrix, combined with a significant pressure differential between the well bore and the reservoir. Of course, these permeability pathways are created through hydraulic fracturing. The pressure of the fluid injection needs to be greater than the cohesive strength of the rock

FIGURE 4

Density Inversion using PP Data Only (Red Line) versus Simultaneous PP-PS Data (Green Line)



matrix (breakdown pressure). Once this level is reached, the formation will start fracturing, at first at the well bore, but soon spreading away from the well bore into the formation.

Determining precisely how and where the rock is fracturing and whether proppant is being placed into those newly created fractures is critical to creating a successful well that not only produces economic amounts of hydrocarbons, but effectively drains the reservoir surrounding the bore hole. This has spawned an entire science behind completion engineering, but shear waves can be utilized to assist this process.

Fractures propagating away from a well bore as a result of injecting high-pressure fluids will seek the weakest portion of the rock matrix that has the smallest amount of tangential stress perpendicular to the propagating fracture (closure stress). These two factors are critical–one having to do with the rock matrix itself, and the other having to do with the stress state of the rock.

The stress state is determined through geomechanical methods and is not discussed here. The rock matrix often will break along pre-existing fractures because that usually is the weakest portion of the rock. Determining the presence and condition of pre-existing fractures is known as fracture characterization. In the absence of natural fractures, the rock matrix will break preferentially in areas that are brittle versus areas that are ductile.

Fracture Characterization

In the presence of anisotropy, shear waves exhibit a property known as birefringence. This occurs when the rock properties being measured depend on the direction of wave propagation. This usually results from the presence of natural fractures in the rock matrix, but also can be the result of differential stress on microcracks or grain alignment.

In the case of cracks and natural fractures, shear waves polarized parallel to the fractures are effectively blind to them, whereas shear waves polarized perpendicular to the cracks will open and close the fractures during propagation, thus sensing a less stiff rock, and therefore will travel more slowly. This results in "splitting" the shear wave into a slow and fast component polarized perpendicular and parallel to fractures, respectively.

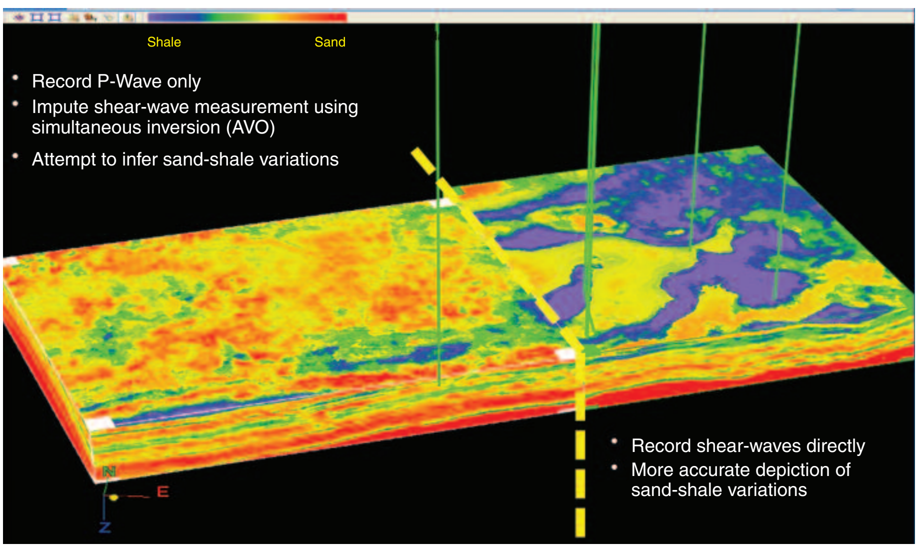
The orientation and magnitude of shear-wave splitting can be correlated directly to the fracture orientation and density, which can prove invaluable in reservoirs where fractures are the dominant source of permeability and porosity. This is the case in two distinctly different play types: fractured carbonates and unconventional shales. Although the two play types are significantly different, the commonality is that accurate characterization of the fracture network is critical to effectively producing from the reservoir because fractures are often the only, or at least the best, source of permeability, and in some cases, porosity as well.

Reservoir Characterization

In the past decade, the perception of organic shale formations has changed

FIGURE 5

3-D Lithology Inversion Cube Showing P-Wave Data (Left) And C-Wave Data (Right)



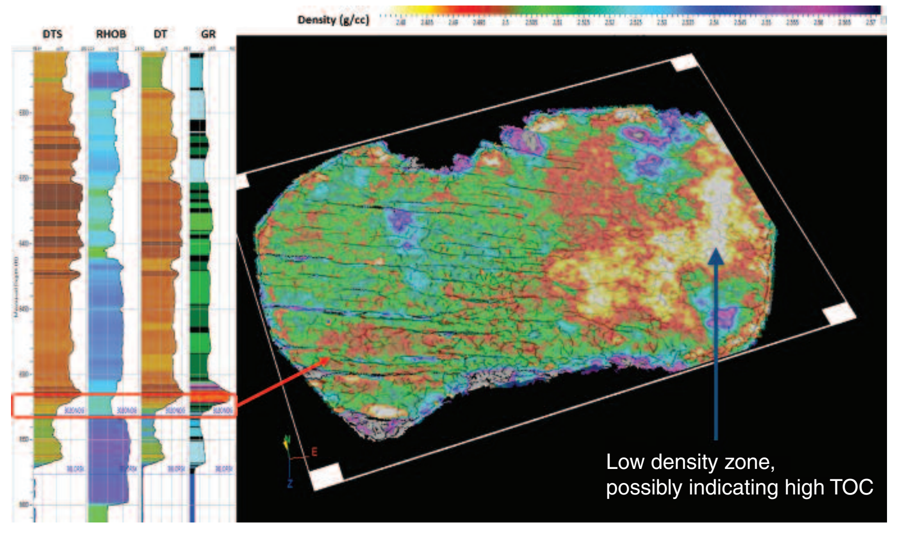
from a homogeneous "source rock" that most explorationists routinely ignored, to a complex, vertically and laterally heterogeneous mudstone, siltstone or marl. Petrophysical analysis of wireline logs, image logs, mud logs and core samples has demonstrated that most unconventional shale reservoirs are highly laminated with interlayered organic shale and silt or limestone that vary in scale from microlayers in the millimeter scale to thicker layers in the centimeter to tens of centimeters scale.

The ability to produce hydrocarbons from this type of formation is dependent on two lithological factors: a high organic content (total organic carbon typically in the range of 3 to 10 percent), and a low volume of clay. This is because TOC volume determines the amount of hydrocarbons present in the formation (in other words, the reservoir is actually the source as well), and clay volume (e.g., illite or smectite) determines the ductility of the formation because clay minerals are highly plastic and will flow under pressure rather than break. Silica and calcium carbonate, on the other hand, are highly brittle and will break under pressure.

Because these mineralogical components have distinctly different densities, this property is most commonly used to characterize rock properties within unconventional shale reservoirs. For instance, TOC has very low density; porosity produces low density; clay has moderate density; silica has high density; and calcium carbonate has even higher density, thus making this property ideal to use. The mineral-based brittleness index calculated by petrophysicists is based on density. Young's modulus, calculated both by reservoir engineers and geophysicists, also requires density.

FIGURE 6

Co-Rendering of Coherency and Density for Lower Marcellus Interval



Courtesy of Santi Randazzo

As discussed earlier and illustrated in Figure 4, incorporating C-wave data with P-wave data produces more stable and reliable density estimates. Figure 6 shows a co-rendering of coherency and density for the Lower Marcellus interval. Density is displayed in color, with warm colors indicating low-density material. Coherency is overlain in black and helps identify fractures. Four log tracks are shown on left. The red box indicates the Lower Marcellus interval, which has been extracted from the seismic inversion (on right).

In summary, this article explores the advantages of using converted-wave data in addition to P-wave data for both conventional and unconventional plays. We see the use of C-wave data increasing tremendously in onshore unconventional reservoirs, where it provides the needed link to engineering parameters. As a result, operators can use this information to better develop their unconventional resources, which we believe will result in substantial cost savings. In addition, in the exploration for and development of offshore conventional reservoirs, we see the use of converted-wave data from seabed acquisition yielding similar results. ❒

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