Seismic Methodologies Adapted for Use in Acoustic Logging*

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Abstract

As our industry transitions to a dependence on the more costly unconventional reservoirs, we strive to find new and more efficient ways to produce from those reservoirs. There has been much focus on drilling and hydraulic fracturing technologies, but what about identifying natural fractures? It is well known that natural fractures exist in the producing zones. It is also well known that only about twenty percent of the fracked area actually produces. If we, as an industry, were better able to identify the naturally fractured zones – we would be able to focus on that twenty percent of producing zones. Currently, the industry uses acoustic logging or imaging to infer or find fractured zones. Unfortunately, however, the move to unconventional reservoirs has brought shortcomings in those techniques to the forefront. For images, widespread use of oil-based mud and the common practice of drilling high angle wells render image data mostly unusable. For shear wave anisotropy, fractures are simply inferred and, for many reasons, that inference cannot be relied on, particularly in unconventional reservoirs. Perhaps imaging and shear wave anisotropy need to make way for different processing techniques. Furthermore, present day tools are only able to detect anisotropy when logged sections are more than five percent anisotropic, leaving the subtle fracture systems undetected. For this last issue, we need look no further than seismic and microseismic techniques for guidance. Due to issues with signal attenuation and a high signal-to-noise ratio, seismic has long used several techniques, such as stacking, to improve results and amplify anomalies. In this discussion, we explore how we have adopted techniques from seismic and microseismic to provide useful and informative results on fractures creating a new processing technique for acoustic logging.
SEISMIC METHODOLOGIES ADAPTED FOR USE IN ACOUSTIC LOGGING

ABSTRACT

As our industry transitions to a dependence on more costly, unconventional reservoirs, we strive to find new and more efficient ways to produce from those reservoirs. There has been much focus on drilling and fracturing reshaping technologies, but what about the ability to recognize and locate naturally fractured zones, and the oil and gas that they contain, inside the productive zones? It is also well known that only about twenty percent of the recoverable oil and gas is produced. Even so, in an industry where better solutions are critical, the naturally fractured zones—whether they are low permeability carbonate reservoirs or tight sands—would be able to focus on that twenty percent of productive zones.

Traditionally, the industry gets acoustic logging or imaging to infer or find fractured zones. Unfortunately, however, the move to unconventional reservoirs has brought about transitions in how utilities are deployed and acquired. The additional complexity and the concern about drilling high angle wells makes image data nearly unavailable. For these reasons, anisotropy fracture data is rarely collected, and for many reasons, those datasets cannot be reclassified through the use of unconventional reservoirs. Perhaps imaging techniques need to rethink themselves and look to other technologies needed to make way for different processing techniques.

Furthermore, present day tools are only able to detect anisotropy when logged sections are more than five percent anisotropic. However, since many unconventional reservoirs are less than five percent anisotropic, the inherent anisotropy in many of these reservoirs may be hidden. For this reason, the industry needs to develop alternative methodologies to help distinguish between anisotropy from fractures and anisotropy from natural interbedding. Rather than just use shear anisotropy to determine anisotropy on a section by section basis, the industry should be able to combine compressional and shear anisotropy to do an overall image presentation. This will allow for a more complete image of the wellbore and the reservoir.

In this research, we compare the waveforms from the X and Y directions with each other and a shear wave anisotropy. The energy from the X and Y directions is compared, and an anisotropy classification is done using the methodology discussed in the previous section. The anisotropy classification can be completed at each depth point. The processing around the borehole is mapped at each depth point. This workflow is an alternative to shear anisotropy and is just one of the many novel methodologies we are studying for unconventional reservoirs.

THEORY

The waveform energy through a homogeneous formation where the compressional splitting is not significant will remain relatively constant as we move through the wellbore. There will be a deep drop picked up by the transmitter. Experiments in Seismic and Seismology research demonstrate the effectiveness of using this method. When the wave velocity through the formation is below the tool threshold, we experience a sharp drop picked by the transmitter. The waveform is muted in time and the compressional splitting of the sound travel through the wellbore.

WORKFLOW

CONCLUSIONS

- Overall idea of mapping fracture networks with compressional waveforms
- Stacking
- Compressional Splitting - though not feasible at this time, still being considered a viable option as tools develop further
- However, induced fractures in the presence of natural fractures tend to have a smaller amplitude or appear as a anomaly in the data.
- Fractures that are consistent with the waveforms are calculated as a series of peaks.
- Experience has only been done thus far in all fracture direction.

LEGEND:

- Fractures seen in core. The baseline corresponds to the X axis, and the Y axis shows the percentage of anisotropy. The X axis is the percentage of anisotropy.
- A blind test was performed in a section. Meaning, that no core results were given prior to the completion of processing.
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- This is what the resulting amplitudes look like for an anisotropy.
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- A differential of the statistical variance is mapped at each depth point to determine the anisotropy directionality of the formation. This is what the resulting amplitudes look like for an anisotropy. This was a blind test in Eagle Ford. Meaning, that no core results were given prior to the completion of processing.

BONUS TEST

This was a blind test in Eagle Ford. Meaning, that no core results were given prior to the completion of processing.