Shale plays can be interpreted and characterized using seismic attributes

Applying established, recently developed technologies, many attributes (structural, rock property and anisotropic) can be generated from seismic data reconstructions, including full-azimuth angle gathers. When properly processed, imaged, analyzed and interpreted, seismic data become a vital source for exploitation of shale plays.

Shale plays represent sources of opportunity for oil and gas companies. and the global economy. As emerging technologies for shale plays evolve, exploration and development programs can be improved measurably. Over the past years, both natural gas reserves and production have grown rapidly.

To ensure a successful shale well, one must drill at the target that is favorable in fluid content, in-situ stress and rock properties. No shales are created equally. Due to their unique nature, shale plays have demonstrated challenges for reservoir exploration and production. Geoscientists have been searching for solutions that can determine and qualify the “sweet spots” in the shale formation, where the output and recovery rate are the highest. Because of its highly heterogeneous nature, identifying and ranking the “sweet spots” requires a number of measurements. Seismic data provide one of these measurements.

Seismic data offer valuable information for all stages of shale play E&P, since they carry signatures related to lithology, fluid and in-situ stress. Special technologies and workflows, however, are required to extract meaningful properties that can be correlated with borehole data and used with confidence throughout the program. To transform seismic data into much-needed information, such as rock properties, in-situ stress and their variation within the formation, requires the support of a number of technologies and workflows.

This article illustrates the available technologies applied in seismic-driven shale reservoir interpretation and characterization, using examples from the Eagle Ford and Barnett shales. It is organized into four main categories: 1) seismic attribute generation and analysis using stacked seismic amplitudes; 2) rock property inversion and interpretation, using reflection angle image amplitudes; 3) stress attribute generation and analysis using azimuthal seismic data; and 4) imaging methods that generate full-azimuth reflection angle data.

Fig. 1. An Eagle Ford study area flowchart shows the workflow, using post-stack seismic data.

STUDY AREAS AND OBJECTIVES

**Eagle Ford shale.** This shale is a Cretaceous sedimentary rock formation, consisting of organic matter rich in fossiliferous marine shale. It has served historically as the source rock to the Austin Chalk reservoir. Only recently has it been recognized as a viable shale play. The Eagle Ford shale formation covers a large area of South and East Texas, ranging in depth from 4,000 to 14,000 ft and thickness from 100 to 330 ft. The Eagle Ford Consists of three primary production zones: oil, wet gas/condensate and dry gas. The seismic data (acquired by Seitel) cover an area of 130 sq mi. The studied area is in the wet gas/condensate zone. Two vertical wells are within the seismic survey area. The shale interval penetrated at the well locations is about 145 ft in thickness. The project objectives are to understand shale heterogeneity; rock properties, particularly rock brittle/ductile quality; and the in-situ stress.

**Barnett shale.** Located in Central and North Texas, the Barnett shale consists of sedimentary rocks of Mississippian age. The Barnett is known as a tight gas reservoir with low matrix permeability. Its depth ranges from 7,000 to 9,000 ft, and its pay zone thickness ranges between 100 and 1,000 ft. The study area covers 75 sq mi. The seismic data were acquired with typical land acquisition geometry, with an average fold coverage of 30. The well inside the survey penetrates a shale layer of approximately 140 ft and shows a few open fractures. The study objective is to understand present-day stress and stress orientation.

**Post-stack attribute generation, visualization and interpretation.** The flowchart in Fig. 1 illustrates the workflow, using post-stack seismic data in the Eagle Ford study area. Well data provide a clear understanding of the formation along the wellbores, such as formation depth, thickness, mineral composition, rock properties, fluid, and the seismic responses and signatures obtained from synthetics. Once the seismic data are
calibrated to the well data, the well data can guide the seismic interpretation, analysis and characterization.

Figure 2 shows three logs—shale log, sonic velocity and P wave impedance (left to right)—from one of the two wells. Examining the logs, one can conclude that: 1) the shale interval is about 145 ft in thickness; 2) mineral content varies, and shale content is low in some of the interval; 3) average interval velocity is about 13,000 ft/sec; and 4) the P wave impedance responds to the shale content change at some intervals. Once calibrated to the well data, seismic data can be used to interpret the shale spatial distribution, and to observe its heterogeneous nature.

Explorationists use post-stack seismic amplitudes to interpret structural horizons and to generate many types of seismic attributes. The top and the bottom of the Eagle Ford formation can be identified easily from the seismic response. Developments in geophysics provide many technologies that generate a large number and variety of seismic attributes. The key process in post-stack seismic attribute analysis is to examine and analyze different seismic attributes, and then narrow them down to a manageable number that contributes to an understanding of the target.

Structural attributes, such as curvature and coherence attributes, are used to delineate seismic scale discontinuities, such as karst (Barnett shale study) and faults. Organized classification attributes based on trace shape similarity, for example, are useful in detecting changes in facies, lithology and rock properties. Physical attributes, like spectral decomposition, sample seismic instantaneous energy variations with frequency and can be useful in evaluating thin bed effects, like tuning.

Figure 3 shows an overlay of curvature and facies attributes along the Eagle Ford interval. The color represents different trace shape (facies). Background discontinuity is the curvature attribute. Co-visualization of structural and stratigraphic attributes reveals some observations: 1) there are a few dominant faults trending North-East to South-West, and one well was drilled in a fault; 2) some faults appear to be boundaries of facies; 3) trace shape varies in the shale interval, indicating the shale’s compositional, depositional and structural heterogeneity.

Figure 4 shows the seismic energy at a higher frequency along the top of the Eagle Ford. The high energy, at the high frequency represented by the bright colors, appears to correlate to the facies in orange (Fig. 3), and may be due to the presence of the carbonate layer encased in the Eagle Ford. A frequency cube generated by spectral decomposition analysis can be used to further estimate tuning thickness.

Rock property attribute generation, visualization and interpretation. The chart in Fig. 5 illustrates the workflow, using true pre-stack, common reflection angle data generated by local angle domain imaging procedures in an Eagle Ford study. Seismic inversion procedures are used to invert seismic data amplitudes sampled by reflection angle, to secure attributes sensitive to lithology and fluid changes. P and S impedances are layer properties directly related to rock properties, such as bulk modulus, shear modulus, Young’s modulus and Poisson’s ratio, etc., from which shale brittleness can be estimated.

Shale brittle/ductile quality can be estimated using the mechanical attributes such as Poisson’s ratio and Young’s modulus. Relatively, low Poisson’s ratio and high Young’s modulus correlate to brittle shale zones, and high Poisson’s ratio and low Young’s modulus correlate with ductile shale zones. The tech-
nique of crossplot domain color coding, (Fig. 6) is then applied to define the brittle/ductile zones and further generate a color cube that represents 3D brittle and ductile shale distributions, Fig. 7. Visualization techniques, such as opacity editing and formation sculpting, are mandatory in understanding the brittle/ductile property along the Eagle Ford interval. Geobodies representing higher brittle zones can be further extracted and mapped. Co-visualizing the geobodies with the facies map, one observes the correlation between facies variation and the brittleness, Fig. 8.

Stress attribute generation, visualization and interpretation using full-azimuth amplitude versus angle (AVAZ) inversion. In-situ stress is one of the key factors that determine a successful drilling program. The challenge is how to accurately estimate the stress intensity and its orientation, using surface-recorded seismic data. Seismic data respond to stress. This can be observed as the azimuthal-dependent behavior of the seismic amplitude and the seismic velocity.

The AVAZ approach measures the changes in amplitude variation, with reflection angle and azimuth affected by the anisotropic media. Horizontal transverse isotropic (HTI) media are assumed for the Eagle Ford shale, given that the structural change is mild, the layer is relatively flat, and the shale is preferentially stressed in the studied area. Typical AVAZ attributes inverted by the HTI AVAZ inversion include anisotropic gradient, stress intensity and azimuth of symmetry axis. Interpretation and visualization techniques are critical to extract and map the stress intensity, and its orientation. Figure 9 is a co-visualization of stress intensity and curvature map, with stress vector superimposed for the Eagle Ford shale interval.

Two types of pre-stack seismic data can be used for AVAZ inversion: 1) Full-azimuth reflection angle gathers, generated with a full-azimuth reflection angle domain imaging technique; and 2) Multiple-azimuth sectors of common reflection point (CRP) gathers.

Imaging methods that generate full-azimuth reflection angle data. Proper analysis of the azimuthal behavior of the seismic data requires preservation of continuous and in-situ azimuth sampling in depth. Unfortunately, such information is either lost or distorted through the application of traditional seismic processing, and imaging methods that make use of azimuthal sectoring. Source-to-receiver azimuthal sectoring of recorded seismic data serves only as an approximation to true sub-surface azimuth. The accuracy of the sectoring process is dependent on the complexity of the velocity model, and the ability of the sectored approach to capture a reliable, continuous sampling of the subsurface. To preserve true sub-surface azimuth, one can adopt a technology that decomposes and images the seismic data into full-azimuth reflection angle gathers and full-azimuth directional angle gathers. Full-azimuth reflection angle gathers carry information on velocity anisotropy and azimuthal AVO.

Full-azimuth reflection angle gathers carry rich reflectivity information that is ideally suited for velocity anisotropy and azimuthal AVO determinations. The angles and azimuths in this procedure are obtained and preserved through a rich, ray-tracing procedure carried out from subsurface points to the surface. In this Barnett example, the main benefit is recovery of a continuous field of in-situ azimuths. An expression of velocity anisotropy is in Fig. 10, which shows a full-azimuth gather at a constant 25° (opening) reflection angle with 0°-to-180° azimuthal sampling.
The second, strong, positive event is the reflection between the Barnett shale and the underlying Ellenburger limestone. If the velocity is not azimuthal-dependent, the event would be flat across the azimuth. The reflection event over the azimuth ranges from 40° to 75° and appears to be lower than the rest of the azimuth sampling, corresponding to the slow velocity orientation. Visualization of continuous-azimuth angle gathers further confirms the observation, Fig. 11. This display shows the reflection amplitude for all angles and azimuths at a single, common reflection point in 3D. The mirror effect of azimuthal-dependent behavior is clear, when data are displayed in 360° azimuth. The analysis can be applied along a structure map to extract the velocity difference between fast and slow velocities. Figure 12 shows the velocity difference map along the bottom of the Barnett shale, obtained from a residual move-out inversion. Co-visualization of the velocity difference and the structure provides a visual correlation between velocity anisotropy and structure features, such as faults and karst, which should be avoided in selection of well locations.

CONCLUSIONS

Seismic data carry critical information related to rock properties and are required for prospect identification, ranking and well planning. Applying established, recently developed technologies, many attributes (structural, rock property and anisotropic) can be generated from various seismic data reconstructions, including full-azimuth angle gathers. Integrated analysis and interpretation of these attributes enables geoscientists to understand the heterogeneity of the studied shale formation; estimate and map the 3D distribution of shale brittleness; and recover stress intensity and its orientation. When properly processed, imaged, analyzed and interpreted, seismic data become a vital source for the exploration and production of shale plays.

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