Eagle Ford shale prospecting with 3D seismic and microseismic data

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Summary

The Eagle Ford Shale in South Texas (Figure 1) is one of the more exciting shale plays in the United States at the current time. Recently published reports of well tests describe gas well rates exceeding 17 mmcf/d and oil well rates commonly in excess of 1500 bopd with numerous 2000+ bopd tests. Acreage lease rates continue to climb as more positive results come from drilling within the trend. A key issue for the exploration companies is finding where to focus acreage acquisition and optimize drilling plans for optimal gas and oil recovery. Our paper will first consider the geologic context of the Eagle Ford and then look at the geologic drivers for locating a productive well. With improved understanding of local rock properties, focus shifts to geophysical techniques, in particular, comparing and contrasting the value of seismic and microseismic data in building a successful exploration plan.

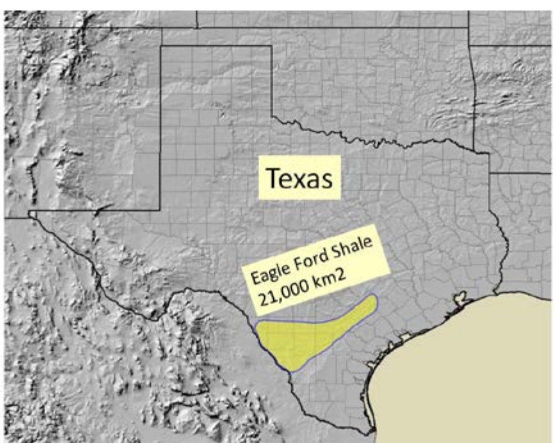

Figure 1: *Location map for the Eagle Ford shale.*

Introduction

Since the first publicly reported, significant gas shale test by Petrohawk in the Dora Martin #1 on October 16th, 2008, (9.7 mmcfg/d), the play has expanded to now cover ~11,000 sq. mi. (~ 7 mmac.) with Oil, Wet Gas and Dry Gas belts predicted based on maturity. Over 250 wells are believed to have either been drilled or permitted in the play. What has emerged is a well defined down dip gas play that transitions rapidly up dip into less well defined wet gas and oil fairways. While there are several large independents who have pioneered the play, the extent of the play area has provided ample opportunity for additional small companies who may be relatively new to making shale plays. The resulting high level of activity has created a rapidly expanding need for viable tools to high-grade areas and reduces drilling risk.

Geologic Setting

The Upper Cretaceous (Turonian?Cenomanian) age Eagle Ford Shale was deposited during an extreme marine high-stand that saw marine incursion deep within the North American continent. The depositional framework in the south Texas area resulted in the accumulation of varying thicknesses of deep water, organic rich marine shales. The form of this marine environment was largely controlled by the interaction of basement zones of weakness, underlying carbonate paleogeography, salt tectonics, and eustatic sea level. Deeper stratigraphic successions impacting the paleogeography are the Louann salt, and the paleo reef margin deposition of the Sligo and the Edwards (Stuart City) formations.

Lowstands preceding and during deposition generated a regional flooring carbonate horizon (the Buda limestone) and an internal carbonate marker (the Kamp Ranch member) that divides the organically rich basal section (lower Eagle Ford or Britton/Pepper Shale) from the overlying leaner and more calcareous member (upper Eagle Ford or Acadia Park). The calcareous source section is down lapped unconformably by the overlying prograding Austin Chalk formation.

Rock Properties

Rock properties of this succession are well suited for seismic analysis. The underlying Buda, a tight (2-3% porosity) massive micritic wackestone, is present regionally in most of the play area and ranges from 40 to 160 feet in thickness. As one would predict, seismic impedance values for this section are quite consistent 48,300 to 51,700 (ft/sec x g/cm^3). A sharp trangressive surface separates the overlying lower Eagle Ford shale from the rigid limestone. These organic shales (50 to 250 feet) often are the richest (4 - 7% TOC) and most porous (7 to 15%) of the Eagle Ford interval. These sub-regional variations are controlled by sea bottom geomorphology created by ancestral margins and syn-depositional collapse features related to salt detachments and diapirs. From an impedance standpoint, the lower Eagle Ford member varies from 31,400 to 35,700 (ft/sec x g/cm^3) being primarily related to variations in TOC and porosity. The upper Eagle Ford member contact with the Austin Chalk is difficult to identify on wireline logs as it is gradational in nature. The gradual decrease of porosity and organic content at this upper interface is not discrete enough to provide a strong interface.

What makes the Eagle Ford play work is a thick, high TOC lower interval which internally develops high porosities generated by maturation. Additionally, evidence suggests that strained but not highly deformed settings enhance performance. Natural fractures of any size assist in providing for a larger permeability network. Another important parameter to establish a viable shale play is the rock's geomechanical properties. Lack of data makes documenting this in the Eagle Ford problematic.

Conventional subsurface data, such as wireline logs, cores and cuttings, are limited in availability to many companies currently exploring the play. Interpretation of these data is often ambiguous at best. As a result, thorough understanding of the regional aspects of the play remains elusive to many companies. It is our belief that modern seismic data and interpretation techniques can add significantly to the database and greatly enhance regional understanding of the play for many companies. Newly acquired 3D datasets provide a continuous characterization of the subsurface, which highlights drilling hazards (faults), and also offers the potential for identifying better reservoir quality intervals (higher TOC shale sections with greater porosity and fractures). Extracting rock properties from the seismic should be the goal of any processing and interpretation effort. Linking the results of well tests to the attributes derived from the seismic will provide operators with a far more reliable predictive capability in any shale play.

3D Seismic Data

Seismic data (Figure 2) offer a number of opportunities to understand potential heterogeneities in the Eagle Ford shale reservoir rocks. Identification of the Austin Chalk and Buda horizons yields well constrained isochron and isopach maps that illustrate the variations in thickness of the target formation. These are central to the development of reliable gas or oil in place maps. Coherence and curvature attributes highlight lineaments associated with small-throw faults and possible fracture trends. Effective interpretation and 3D visualization of the target shale section can illustrate a host of anomalies that might impact well positioning and reduce drilling risk. Amplitude variations of the Eagle Ford Buda horizon could also flag improved Eagle Ford shale zones. These are techniques that are now used routinely and are very effective. It is our experience within shale plays that processing the data with a focus on phase and impedance variations will ultimately be the key to identifying the sweet spots in this trend. Critical to achieving this will be the collection of high frequency, high fold data with a focus on long offsets and full azimuth data.

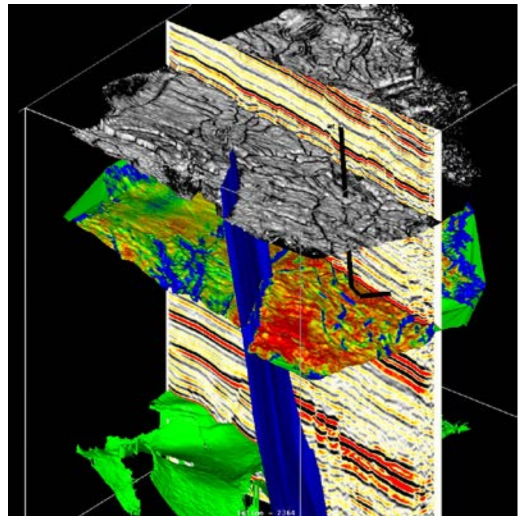

Figure 2: *Composite of attributes in Eagle Ford shale*

In the processing of the current Eagle Ford 3D seismic, we have the opportunity to extract even more information from the shale section. Long offset and full azimuth 3D datasets (Figure 3) allow us to determine anisotropic parameters for the shale. Layer anisotropy (VTI – Vertical Transverse Isotropy) and azimuthal anisotropy (HTI – Horizontal Transverse Isotropy) may help infer clay content and fracture presence.

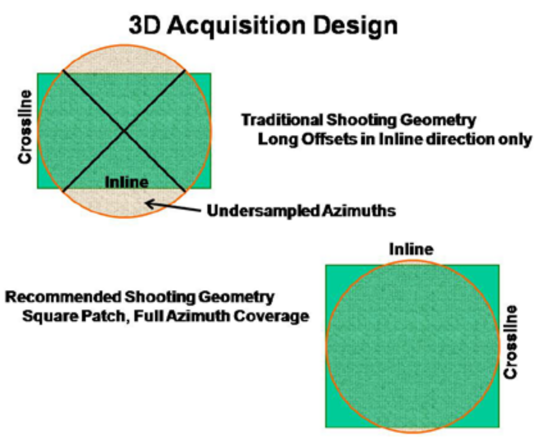

Figure 3: *Comparison of the more typical rectangular receiver patch versus the square patch needed for HTI processing..*

Rock property changes typically apparent in far offset gathers but muted in stacked volumes offer insight into the petrophysics. Careful attention to this aspect of the seismic shoot enhances the overall image of the section and provides fracture or stress information critical in planning drilling programs. It is also necessary to address anisotropy prior to any elastic inversion attempt. Far offset amplitude variations due to poor characterization of the velocity and anisotropy fields will lead to incorrect elastic parameters in the inversion.

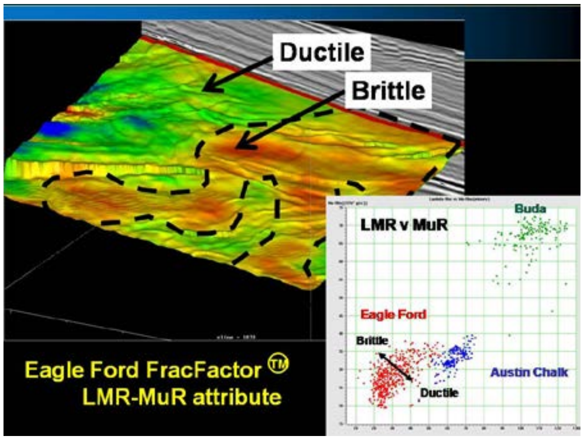

Figure 4: *Specialized attribute depicting rock strength*

With the refined processing products described above, it is possible to begin extracting rock property information through an inversion of the seismic. Acoustic impedance inversion is the simplest and most robust first step in the pursuit of Eagle Ford rock properties. The inversion uses a 3D model and an estimation of the seismic wavelet to convert the seismic volume to an impedance volume. Rock property studies in the Eagle Ford indicate that impedance and porosity in the Eagle Ford are well correlated. A more specialized elastic inversion product is the volume in Figure 4, designed to highlight changes in rock strength. Ultimately a combination of inversion and surface attributes calibrated with core, log and production data are the key to understanding the shale potential.

Validation with Microseismic Frac Monitoring

While seismic offers an indirect measure of rock property variations across the shale, microseismic monitoring of the hydraulic fracing (Figure 5) used to create permeability in the section provides a more direct measurement of reservoir geomechanics. Surface arrays, buried arrays and borehole arrays provide different techniques to measure the micro earthquakes caused by the fracturing of the rock. Each has it's own positives and negatives depending on the target depth, length of the horizontal well, surface conditions and rock strength. Processing technology to identify microseismic events is in its infancy but shows promise for tracking the multistage fracs. Monitoring the frac can help identify the proportion of rock volume available for production. Integrating the microseismic results with the processing products, inversion and surface attributes is the best way to understand and adjust the drilling plan for optimal hydrocarbon recovery.

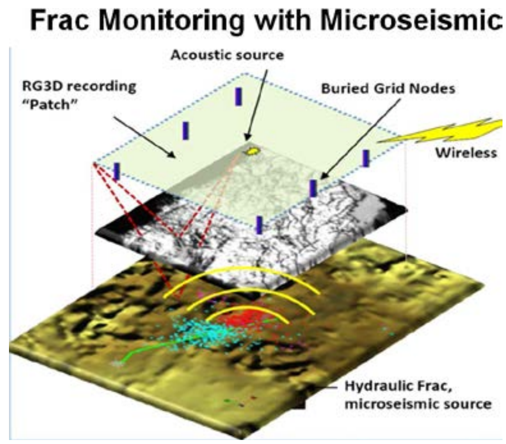

Figure 5: *Frac monitoring using a buried array to record microseismic events.*

Conclusions

The pursuit of Eagle Ford acreage and the designing of an Eagle Ford drilling campaign is best accomplished through a comprehensive understanding of the geologic framework coupled with a focused interpretation of the seismic and microseismic data. This shale is one of the more exciting domestic shale plays, and presents ample opportunities to make and lose money. The smart operator will utilize all the tools available to study the target section while recognizing the limitations of the technology.

Acknowledgements

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Suggested Reading

Charles Sicking and Stuart Nelan, 2009, Offset and aperture requirements for azimuth parameter estimation using azimuth migration scanning. SEG Expanded Abstracts 28, 1157-1161

Galen Treadgold, Charles Sicking, Victoria Sublette,Gary Hoover, 2009, Azimuthal processing for fracture prediction and image improvement, 78th Annual International Meeting, SEG, Expanded Abstracts, 988–992