Shale play characteristics a case study of Eagle Ford shale

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Abstract

We used a model based inversion solving for Vp, Vs and Density and computed Young's modulus and Poisson's ratio to determine rock brittleness/ductility and total organic carbon (TOC) from rock properties. Although the lower Eagle Ford shale appears fairly consistent in its properties, we note specific variations in those rock properties that suggest they can be used to improve prospecting for hydrocarbons in the Eagle Ford shale play.

Introduction

The Eagle Ford formation is Middle-to-Upper Cretaceous age (Turonian and Cenomanian) consisting of a series of varying thicknesses of deepwater, organic and carbonate rich marine shales. The formation is divided between two members the Upper and Lower Eagle Ford. The Upper member is lower in total organic carbon (2-5% TOC) with the Lower member having much higher TOC (4-7%). Porosity in the Lower member is in the range of 7-15% and the Upper member is less porous with porosities running 7-12% (Treadgold et. al. 2011).

The Eagle Ford shale is a calcite rich shale that consists mainly of the minerals (Hildred & Schmidt 2011) quartz (av. 13%), calcite (av. 50%) and clay (av. 27%). This gives the shale the fabric needed for hydraulic fracturing to be successful. The higher the calcite content the more brittle the shale becomes.

The Lower Eagle Ford is the primary target for hydrocarbon production. The typical approach is treat the Eagle Ford like other shale plays where the production is treated more like a mining operation than the conventional hydrocarbon production approach. Horizontal lateral wells are drilled and hydraulic fracturing is done to stimulate fluid flow since the shale has poor permeability. Multiple fracture stages are done with each possibly having multiple perforation clusters.

In this type of hydrocarbon prospecting, seismic is typically used to determine shale thickness, presence of faults, karsts and other drilling hazards to avoid when planning the laterals for the wells. Drilling often will use LWD (logging while drilling) to determine if the lateral is in zone or not and attempt to make steering decisions in real time. After the lateral is drilled, image logs may be ran to try and determine reservoir quality and possibly identifying the presence of natural fractures.

The question to ask is with the current methods of hydrocarbon prospecting in organic shales "Are all organic shale wells producing at or near there theoretical average?" According to Miller et. al. (2012) approximately 50% of organic shale wells are producing within 10% of their theoretical average and 20% of the fracture stages are producing less than half their theoretical average. This strongly suggests there is an opportunity to improve the economics of drilling and production from organic shale wells.

Once a lateral is drilled, the reservoir is fixed in terms of what is the available reservoir quality. The focus then becomes how one best can design the fracturing stages, number of perforation clusters, location of perforation clusters, etc.

What we propose is looking at organic shale plays in a more regional view where the opportunity to design laterals that penetrate areas with the highest reservoir quality within the constraints imposed on well location placement from lease requirements, boundaries, etc. Our method uses the seismic data to calculate rock properties Vp, Vs, and density and computes TOC and brittleness/ductility from these rock properties. Using this information, the opportunity for more optimal well placement avails itself.

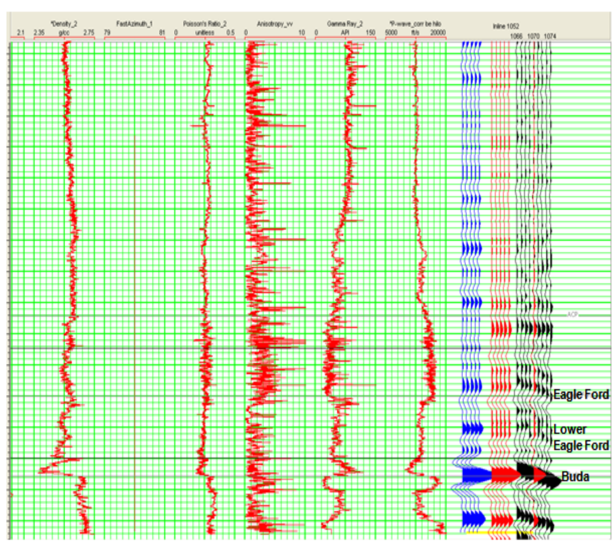


Figure 1: Well log display of pilot hole drilled. The blue traces are the zero offset synthetic repeated 5 times, the red traces are the composite trace from the seismic repeated 5 times and the black traces are the seismic around the well bore. Note: the Upper and Lower Eagle Ford are resolved.

Method

We took a wide-azimuth survey and processed it using offset vector tiles (OVT) to preserve azimuthal information. The data was then migrated using an orthorhombic migration (Wojslaw & Stein 2011) to correct for both VTI and HTI anisotropy. The resultant offset-azimuth CDP gathers underwent gather conditioning that was amplitude preserving. We applied a bandwidth extension algorithm (Smith et. al. 2008) that increased resolution on the CDP offset-azimuth gathers. In Figure 1 the well tie shows how we are now able to resolve the Upper and Lower Eagle Ford. The azimuths were then stacked and the data underwent an inversion that used a simulated annealing algorithm to solve for the three petro-elastic parameters Vp, Vs, and density (Yang & Yu 2009). As can be seen in Figure 2-4 the inverted Vp, Vs and density match the well data. We then computed the moduli bulk, shear and Young's modulus and Poisson's ratio.

After the inversion was completed we calculated a Lower Eagle Ford geobody (Figure 5) by cross-plotting density versus bulk modulus and picking the lower density (< 2.5 g/cc) portion of the cross-plot. We used the geobody as a mask to identify only the organic shale and calculated minimum and maximum properties and thickness.

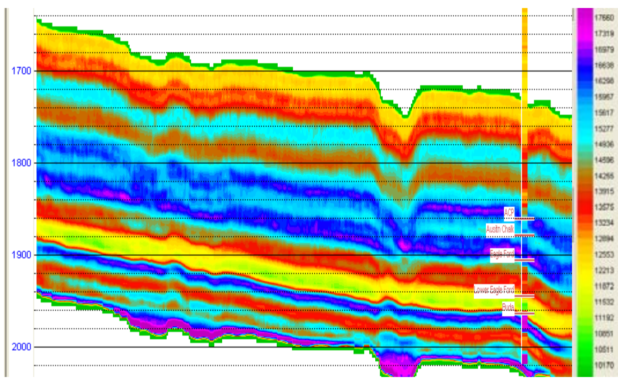


Figure 2: Vp from pre-stack inversion with Vp log overlaid

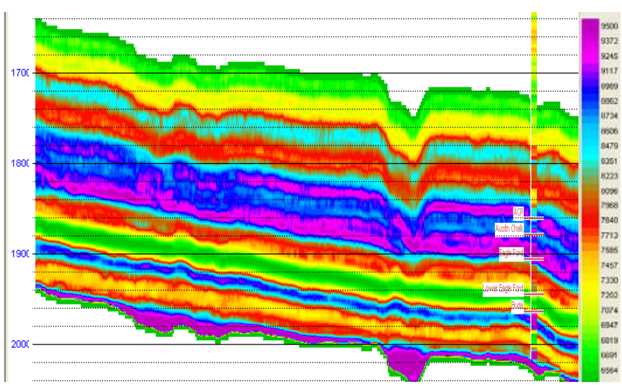


Figure 3: Vs from pre-stack inversion with Vs log overlaid

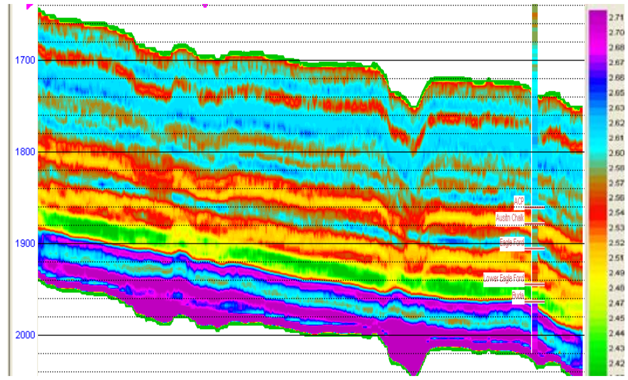


Figure 4: Density from pre-stack inversion with density log overlaid

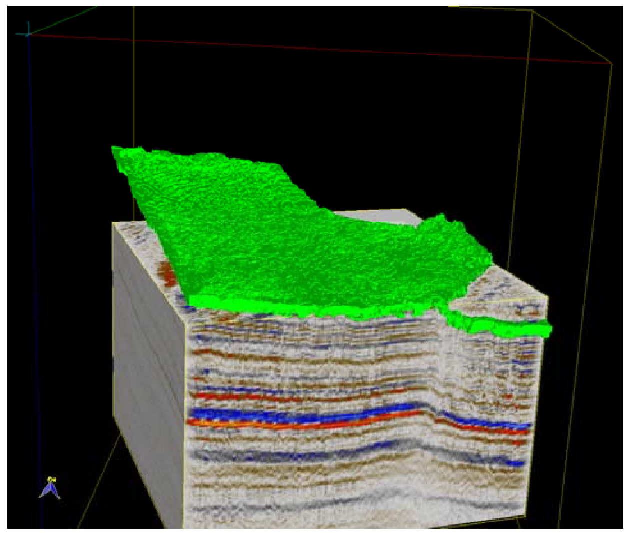


Figure 5: Geobody (green) with seismic cube displayed

Theory

Our model based inversion uses a simulated annealing algorithm to solve the least-squares problem by minimizing the error of the following objective function

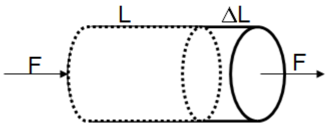
$$LS = \sum_{j=1}^{n}\sum_{i=1}^{m}\left[T_{pp}^{*}(\theta_i, t_j) - T_{pp}(\theta_i, t_j)\right]^2 + \alpha\sum_{k=1}^{l} c_k^2$$

Where T_{pp} is the synthetic model response of the updated model and T_{pp}^{*} is the seismic data response (PP for P-wave only), □ is a weight factor and *c* represents constraint(s) which helps guide the minimization of the objective function. The dual summation is applied over all incidence angles for all two-way times of the interested interval for inversion.

The synthetic model is created from an initial geological model consisting of Vp, Vs and density values which have been modeled from well logs and horizons that define zonal boundaries identifiable in the seismic data. The inversion then computes reflectivity from the changes in rock properties in the layers defined by sample boundaries. We use the Aki & Richards approximation for the reflectivity and convolve a set of deterministic wavelets extracted from the different angle ranges.

Once we have Vp, Vs and density we can then compute our moduli, Young's, shear and bulk and Poisson's ratio.

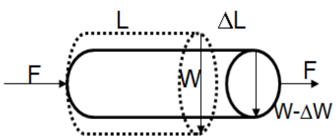
Young's modulus is a measure of the stiffness of a material and is the slope of the elastic portion of the stress-strain curve (Hooke's Law). As can be seen in Figure 6 Young's modulus is the change in length in the longitudinal direction when a longitudinal stress is applied.



$$E = \frac{(F/A)}{(\Delta L/L)}$$

Figure 6: Young's Modulus E

Poisson's ratio is a strain/strain ratio of a material in the elastic limit. In Figure 7 we show that when a material is stretched in the longitudinal direction it contracts in the transverse direction. Poisson's ratio has been linked to post-elastic deformation behavior in crystalline materials (e.g. rocks) which shows an uncanny prediction of brittle vs. ductile behavior. Materials with high Poisson's ratio exhibit ductility when strained beyond the elastic limit and low Poisson's ratio materials exhibit brittle behavior (Greaves et. al. 2011).



$$\nu = \frac{(-\Delta W/W)}{(\Delta L/L)}$$

Figure 7: Poisson's ratio ν

From Young's modulus and Poisson's ratio we can calculate a brittleness/ductility parameter by dividing Young's modulus (stiffness) by Poisson's ratio (ductility). This brittleness/ductility attribute can then be used to get a relative measure of the rock's tendency to fracture under increased pressure.

One note of caution, is that our estimates of Young's modulus and Poisson's ratio are dynamic (velocity) not static (mechanical). The above definitions are static not dynamic. Sungupta (2012) points out that we should be able to use rock-property inversion data to calculate relative rock strength spatially even if there are uncertainties in the relationships between dynamic and static properties.

To estimate TOC content we note that Sondergeld et. al. (2000) found a strong dependence of bulk density on TOC content and little or no dependence on clay content in the Kimmeridge organic shale. Bulk density decreased linearly with increase in TOC content. We have found this relationship holds in other organic shale plays including the Eagle Ford.

Results

In Figure 8 we show the anisotropy log (velocity anisotropy) overlaid on the brittleness/ductility attribute. One can see that when the brittleness increases we have an increase in velocity anisotropy (in the chalk and limestone) and in the shales we see virtually no velocity anisotropy from fractures. Cores were taken and the Eagle Ford shale had healed fractures (calcite filled) and thus shows little indication of fracturing on the anisotropy log. However we do see in the Austin chalk and Buda limestone indications of velocity anisotropy up to about 4-6%.

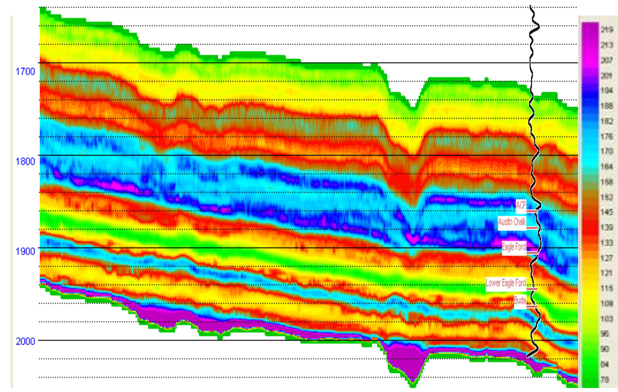


Figure 8: Brittleness/Ductility with velocity anisotropy log overlaid

The geobody results in Figure 9 give us an approximate estimate of thickness of the Lower Eagle Ford from a regional point of view. The thickness varies from about a minimum of 24 meters to a maximum of 40 meters. The majority of the organic shale is at least 32 meters thick.
The Lower Eagle Ford in this region varies from 4-7% TOC content. Since bulk density decrease linearly with TOC content bulk the lower density regions of the survey should have much higher TOC content. Figure 10 shows the minimum density from the inversion analysis in the Lower Eagle Ford shale.

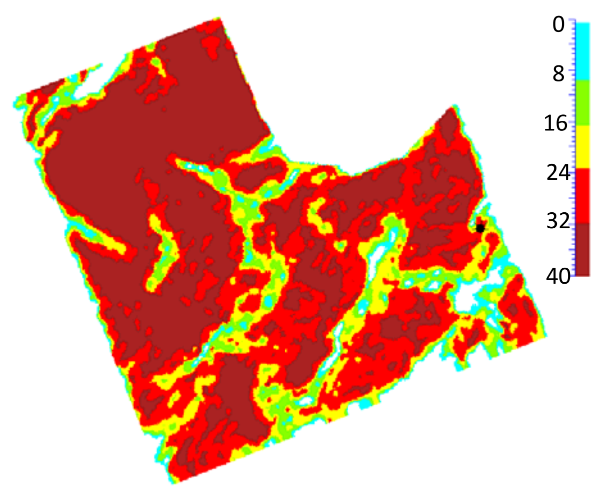


Figure 9: Lower Eagle Ford shale thickness in meters

Probably the most interesting result in this study is seen in Figure 11. This figure represents the regional variation in brittleness/ductility in the survey. The highest brittleness zones are separated by the larger fault zones in the survey. The other notable point is that in this display you can see major faulting that mostly have an approximate orientation of 30 degrees from north. The anisotropy log indicates that local fracturing has an orientation of 80 degrees from north. The faulting may be representative of a past stress orientation of 30 degrees which is now presently 80 degrees.

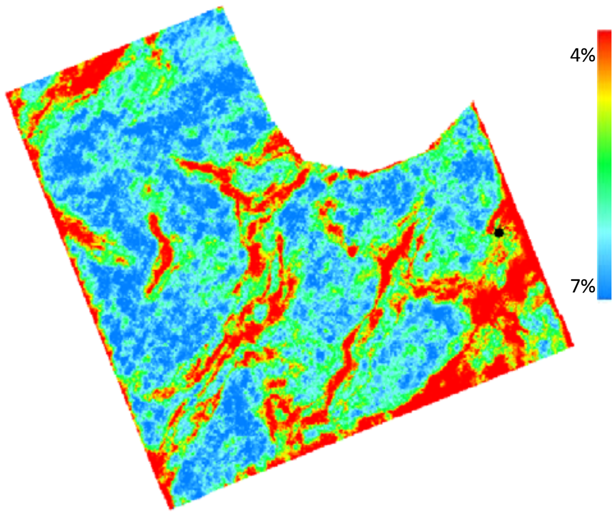


Figure 10: Estimated TOC (using minimum density) in Lower Eagle Ford shale

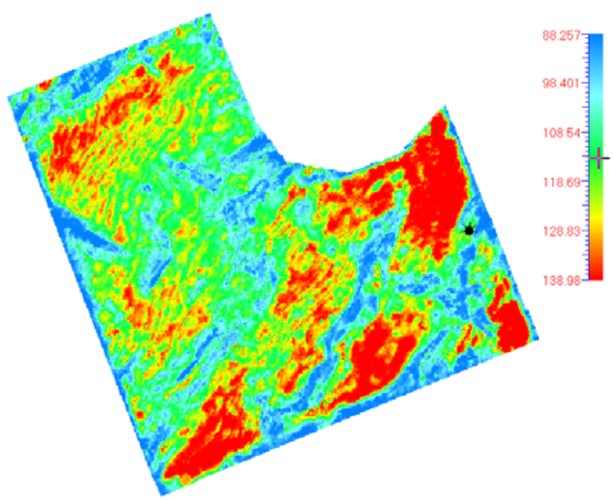


Figure 11: Brittleness/Ductility of Lower Eagle Ford shale

Conclusions

We have shown that using a model-based inversion that Vp, Vs and density can be used to create Young's modulus and Poisson's ratio volumes to compute a brittleness/ductility volume that can aid in determining regional characteristics of the organic shales such as the Eagle Ford.

From these regional characteristics improved lateral well plans can be made. We are able to see TOC content from the density volume and estimate where higher TOC can be found. Along with a better idea of the brittleness of the organic shale the two attributes combined can aid to increase success in production from organic shale plays.

Acknowledgments

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