Use of Pre-Stack Seismic Inversion and Post-Stack 3D Seismic Attributes to Predict and Improve Natural Gas Production in the Mississippian Fayetteville Shale, Arkoma Basin, Arkansas

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Production from gas shale is mainly controlled by the volume of gas-in-place (free and adsorbed), by the density, orientation and content of natural fractures, and by the present stress field and the mechanical properties of the reservoir rock that determine its response to fracture stimulation.

In the Fayetteville Shale, wells in close proximity display large variations in production, suggesting that the parameters influencing production change rapidly over short distances. Unfortunately, in most shale gas development projects, direct measurement of reservoir parameters and rock properties is made in only a few, widely spaced vertical pilot wells, while production is from numerous horizontal wells from which little geologic reservoir data is collected. For example, in the Fayetteville Shale play, approximately one well in ten has been fully logged through the entire reservoir section. In the absence of extremely dense subsurface sampling, three-dimensional seismic data must be used to provide the spatial coverage required to predict productivity and describe reservoir properties at undrilled locations.

Seismic data has commonly been used in shale plays for structural interpretation and to guide horizontal well placement, but is less frequently used to characterize rock properties and predict well performance. Without reliable seismic-based predictive models, operators depend on statistical sampling of the subsurface through drilling to establish expectations of future well performance, and a trial-and-error approach to well spacing, completion and stimulation techniques as the primary means to optimize resource development. There is a significant opportunity to improve forecasting and accelerate learning by using seismic data to improve predictions.

Southwestern Energy has taken two distinct approaches to using 3D seismic data to understand and predict well performance in the Fayetteville Shale play.

The first is to cross-correlate properties derived from elastic inversion, pre- and post-stack seismic attributes directly with well performance to develop a multi-attribute statistical relationship between seismic and normalized production. Predictive maps of well production for the Fayetteville Shale have been constructed using these correlations in one 50 sq. mi. area, which allowed us to predict short-term production of 9 of the 13 wells drilled and completed during the subsequent six months, with accuracy better than ±15%. However, this direct correlation between multiple seismic attributes and production doesn't provide specific insight into the controlling physical factors (i.e. rock properties), and therefore is only of limited value in evaluating alternative development schemes and completion techniques.

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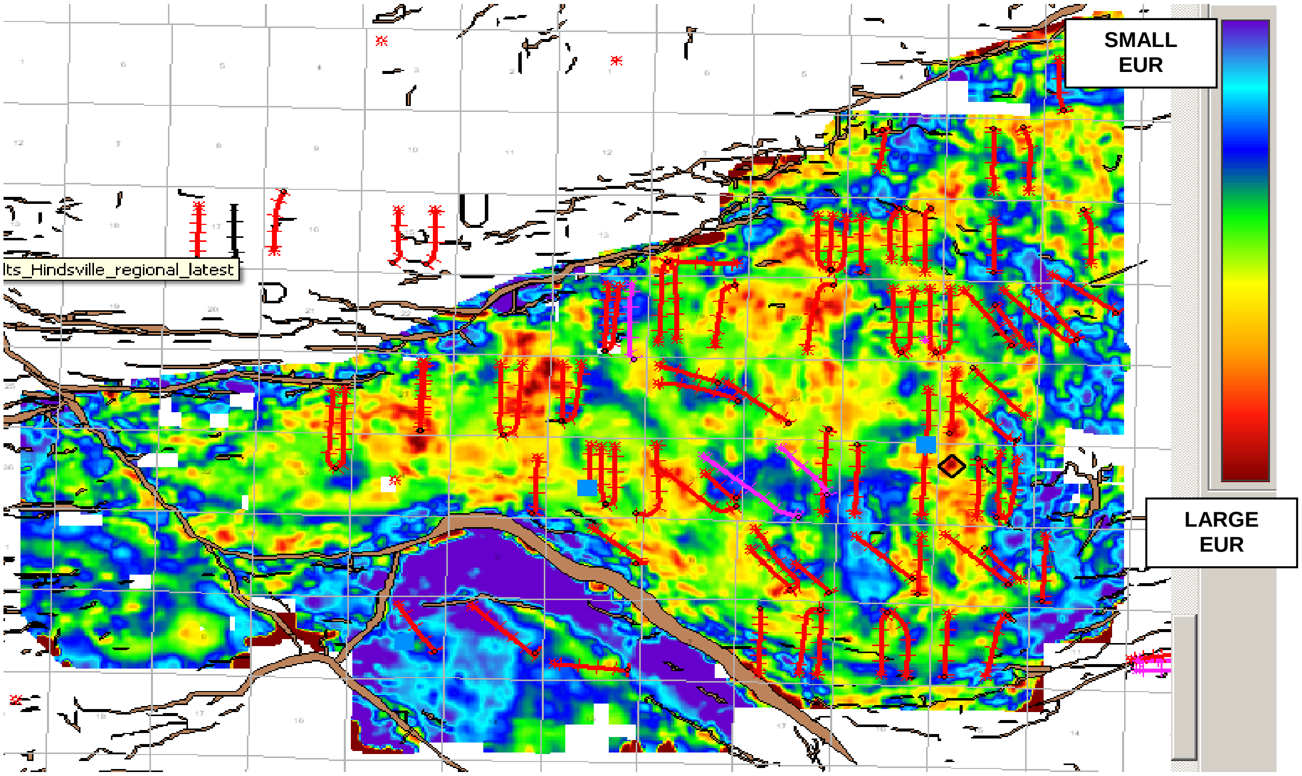

Fig. 1: Prospective map of normalized EUR, based on validated linear multi-regression of four seismic attributes

The second method uses seismic attributes calibrated to well logs, to first predict rock properties, and from these rock properties, to then predict well performance. Using this technique in several pilot areas, we have built three-dimensional geomodels populated with matrix and natural fracture properties, and incorporating all relevant geological, geophysical and engineering data, including knowledge of induced fracture characteristics derived from microseismic data. These static models are calibrated to well performance through history-matched reservoir simulation, and have, to the limited extent we have applied them, shown some predictive value in areas with sufficient calibration data. Our reservoir engineering models suggest that natural fractures are more important than previously thought in controlling production from the Fayetteville Shale, and horizontal FMI logs show that natural fractures are more prevalent than previously recognized. We are currently working to refine detection and characterization of natural fractures and stress field using seismic attributes calibrated by horizontal FMI and cross-dipole sonic logs.

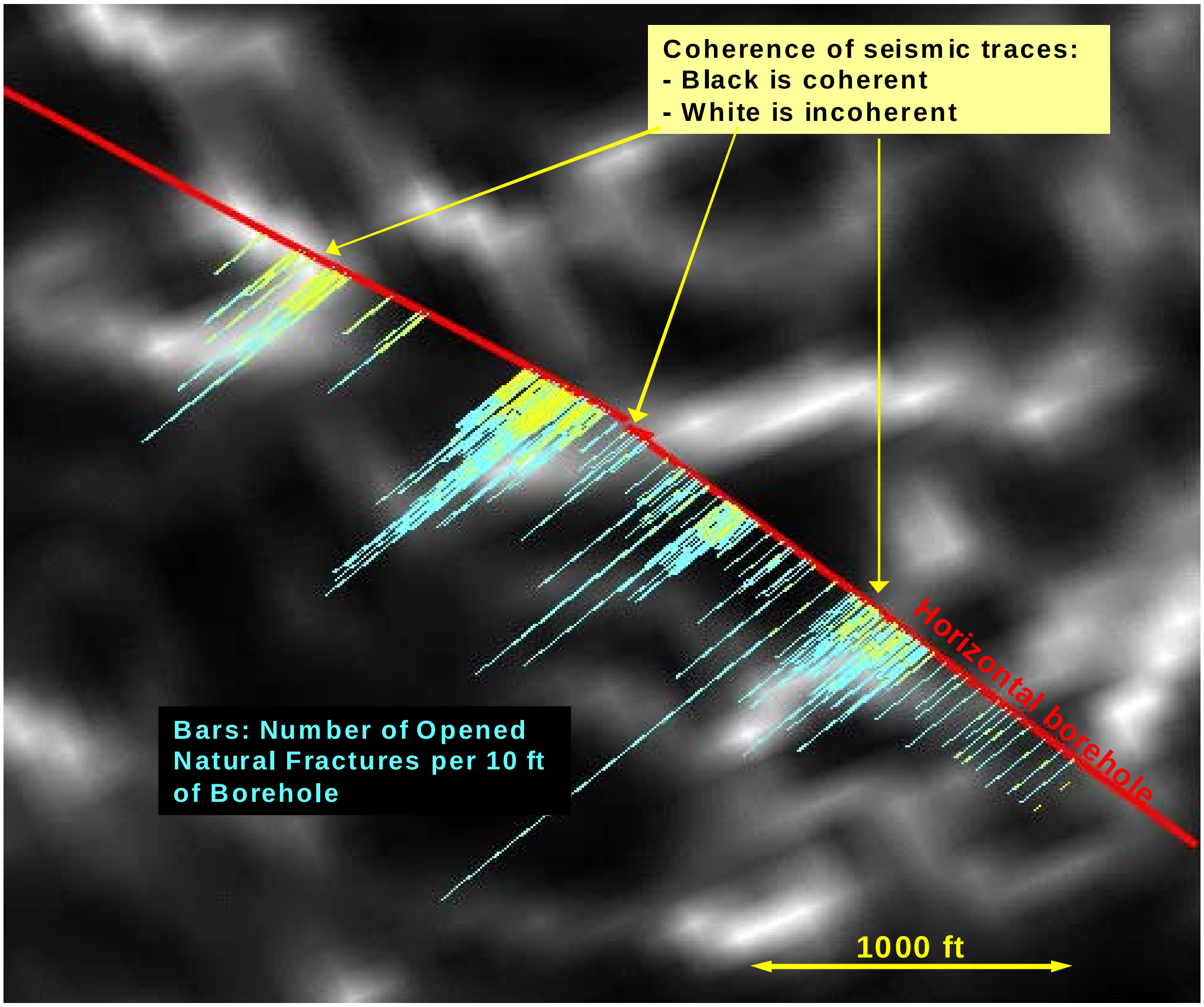

Fig. 2: Plan view of a horizontal borehole with opened fractures density calculated from FMI log and 3D seismic incoherency. Good match between horizontal FMI and incoherency of seismic traces.

Because the geomodeling technique explicitly incorporates rock properties and reservoir simulation, we can use these models to evaluate the effects of varying completion techniques and development schemes, and to help optimize key development parameters like well spacing and fracture stimulation design.

Regardless of the specific method used, applying geostatistical methods to geophysical, geological and engineering data in order to predict future well productivity requires high-quality input data and judicious use of geostatistical methods. We improved our seismic inversion process by better preservation of low-frequency amplitude, use of more pilot hole data and, below 4 Hertz, seismic migration velocity. Proper extraction of attributes from the seismic data and normalization of production data are very important in making either approach valid. Using validation techniques to avoid over-fitting of the target data is key to obtaining statistical correlations which are truly predictive. We are working with programmers to improve existing software to more effectively extract seismic attributes and correlate them with logs.

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Geomodeling introduces additional challenges. It requires not only accurate input data, but also insight into underlying structural and depositional processes to ensure that reasonable models are built. Handling the difference in resolution between core, log, and seismic measurements is particularly difficult.

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