NEW TECHNOLOGIES AND INTEGRATION FOR OPTIMIZING WELL PLACEMENT AND PRODUCTION

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RESUMEN

Nuevas tecnologías e Integración para optimizar la ubicaciòn de pozos y la producción en recursos no convencionales

Cuando se comparan con los recursos convencionales, los recursos no convencionales se han clasificado anteriormente como antieconómicos, ya que requieren estimulación artificial como la fracturación hidráulica con el fin de crecer suficientemente la movilidad de los hidrocarburos para que migren hacia el pozo. Con la llegada de precios adecuados del combustible y de los avances tecnológicos, estos yacimientos son ahora económicos. El cambio positivo en el Retorno de Inversión es el motor para la expansión de la industria de la energía en este tipo de yacimiento. Este artículo detalla nuevas tecnologías, herramientas y flujos de trabajo diseñados para facilitar la descripción precisa de yacimientos no convencionales, en particular de tipo "*Gas Shale*". Las herramientas y flujos de trabajo están diseñados para proporcionar soluciones para los tipos de yacimientos no convencionales, utilizando una estrategia de análisis integrada y de multi-dominio durante todo el proceso, desde la fase de procesamiento (*Full Azimuth*) hasta la parte de ingeniería de yacimientos para reducir y controlar las incertidumbres en la toma de decisiones, el diseño de pozos, la perforación misma y en el seguimiento de producción.

INTRODUCTION

The challenges for optimal well placement and completion in unconventional resource plays rely on a complex array of seemingly independent variables such as heterogeneous rock properties, anisotropy and natural sub-seismic fracture networks. To ensure 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.

To maximize production rates, criteria such as water saturation, hydrocarbon content, physical and mechanical rock properties, *in-situ* stress fields, faulting, and fracturing must be evaluated and then quantified for integration into a single model. The results can efficiently impact drilling and development decisions. Both wireline log data (for rock and reservoir parameters) and seismic data (for rock fabric and property information between wells) need to be correlated into an integrated interpretation for reservoir characterization and discrete fracture model creation.

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. For example, seismic data provide one of these measurements. Interpreting high-quality seismic data through enhanced visualization techniques guides the geoscientist to a more precise characterization of the reservoir, enhancing predictions of the spatial and temporal conditions of trapping systems, the distribution of subsurface lithology, and reservoir properties, calibrated to the in-situ conditions observed at the wells.

New technologies help to identify and mitigate potential hazards that drilling engineers may encounter by integrating interpretation, characterization and reservoir modeling information in a unique 3D canvas, leading to a reduction in drilling risk.

The evaluation of rock and reservoir parameters is closely associated with the development of new technologies. These technologies are reviewed and illustrated by Barnett and Eagle Ford examples, and culminate in well planning and drilling (geosteering).

EXAMPLES

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 average fold coverage of 30. The well inside the survey penetrates a shale layer of approximately140 ft. and shows a few open fractures. The study objective is to understand present-day stress and stress orientation.

METHOD

Both the Barnett and Eagle Ford reservoirs have a propensity for brittleness which can make them susceptible to fracturing. It should thus be no surprise that the industry has focused on predicting areas of potentially increased permeability due to the presence of natural fracturing that may then be enhanced with hydraulic fracturing.

The current methodology is to identify these “sweet spots” and optimize production with intense horizontal drilling and hydraulic fracturing. Wells and sometimes conventional seismic are commonly used, when predicting rock properties, to determine the trend of maximum stress, and, then define the wellbore path in order to facilitate hydraulic fracturing. Some companies are also acquiring microseismic data at their wellbores for more direct measurements of anisotropy rock properties, while others are mostly tying zones of increased brittleness and drill in between existing wells. In the Barnett Shale, for example, the net result for these workflows has been commonly reported as 80% of the production from 30% of the completions.

Why do 70% of the completions fail to significantly contribute to production? First, the wellbore may not be optimally positioned at an appropriate angle to regional stresses. This may be a result of inaccurate rock property calculation and mapping, or complex structural fabric overprinted by several regional events. Additionally, the structures of interest, fractures and small faults or facies changes, are sub-seismic and cannot be delineated from conventional seismic using conventional processing. Finally, in the case where only wells are used for delineation, the underlying assumption is that rock property information can be carried between the wells. The problem with looking at an extensive shale formation and pursuing a simple infill program is that these reservoirs are not isotropic or homogenous. The actual reservoirs, like in the Eagle Ford, can be the result of drastic facies changes, and the rock properties are complex. In order to create models that are accurate and successfully predictive, a more rigorous approach is required for optimizing well placement.

New, enhanced-performance technology and tools designed to facilitate accurate reservoir characterization are now available. These provide solutions for unconventional play types with an integrated and multi-domain approach across the entire workflow, from full-azimuth processing and imaging up to reservoir engineering, to reduce uncertainties in the planning, drilling and completion decision-making process.

Despite the challenges of vertical resolution, conventional seismic data offer valuable information regarding lithology, fluid contents and in-situ stress events. For the accurate extraction of rock properties from seismic data without azimuthal biasing, a new full-azimuth angle domain imaging and analysis technology has been designed to deliver unsectored data for subsurface velocities, structural attributes, medium (rock and fluid) properties and reservoir characteristics. As this process provides in-situ recovery of continuous azimuth and continuous angle pre-stack data in depth, additional information from both modern and legacy seismic data (especially wide and rich azimuth data with long offsets) is produced. In low permeability and fracture system plays, this technology, with its solutions for anisotropic tomography, provides stress and fracture detection for accurate reservoir characterization correlated to shale properties.

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 AVA determinations. The angles and azimuths in this procedure are obtained and preserved through a rich, ray-tracing procedure carried out from subsurface points. In a case study of the Eagle Ford formation, full-azimuth reflection angle gathers for a 36-degree opening angle are shown in the Figure 1 (upper left) below. In this example, the main benefit is to recover the continuous filed of in-situ azimuths. If the velocity is not azimuthal dependent, the strongest seismic event (in the red rectangle) would be flat across the azimuth. Reflections appearing to be lower would indicate a lower velocity for those ranges of azimuth.

The accompanying minimum stress fracture orientation map (Figure 1, upper right) with measured intensity overlies the most apparent brittle zones shown in rainbow colors. To map the spatial distribution of the estimated highest brittleness material (vs. ductile), mechanical attributes such as Poisson’s ratio and Young’s modulus were calculated from a simultaneous inversion and analyzed through advanced cross-plotting for geobody detection and mapping. 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 technique of cross-plot domain color coding (Figure 1, lower right) is then applied to define the brittle/ductile zones and further generate a color cube that represents 3D brittle and ductile shale distributions. 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 (Figure 1, lower left) and mapped or co-visualized with any other attributes to observe the correlation, for example with seismic facies.

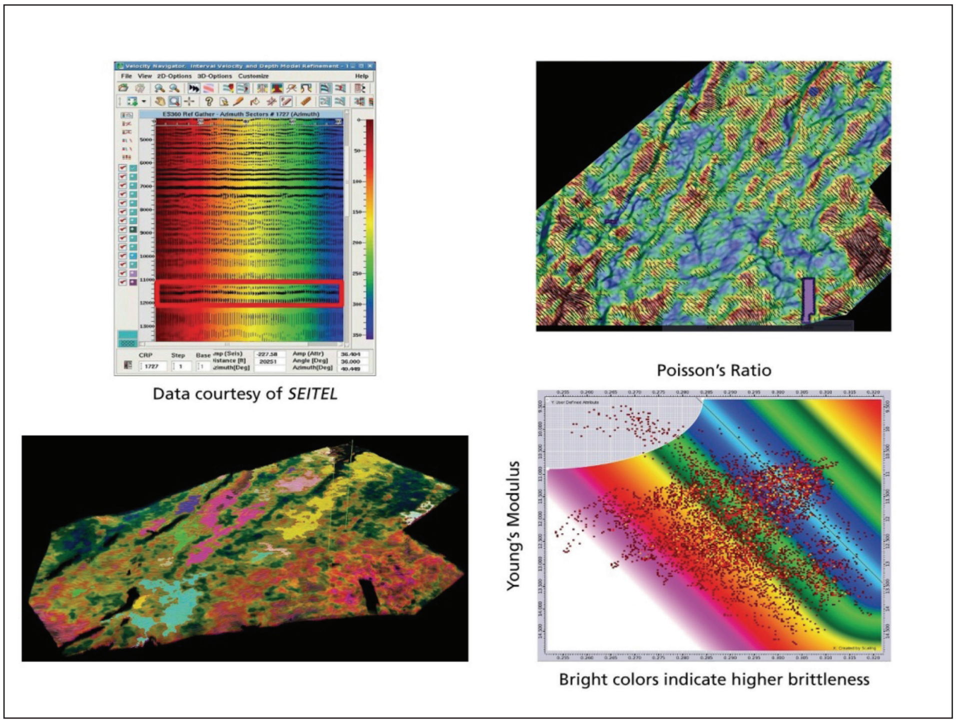

Figure 1. Full-azimuth, seismic-driven reservoir characterization from a full azimuth acquisition in the Eagle Ford – Upper left: Two dimensional representation of a full azimuth reflection angle gather at a constant 36 degrees opening angle; Upper right: Vectors representing minimum stress direction combined with fracture intensity and curvature attribute; Lower left: Identification through opacity of brittle and ductile zones with detected geobodies correspond to the most brittle zones.

Interpreters 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 poststack 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, 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 2 shows an overlay of curvature and seismic facies attributes for the Eagle Ford interval. The color represents different trace seismic response or trace shape within the interval of interest (facies). The background is the curvature attribute. Co-visualizing both attributes leads to some observations: 1) there are a few dominant fault (NE-SW), one well is located within the fault zone. 2) A good correlation between facies distribution and structural pattern 3) a facies variation which indicates a lateral heterogeneity of the quality of the shale.

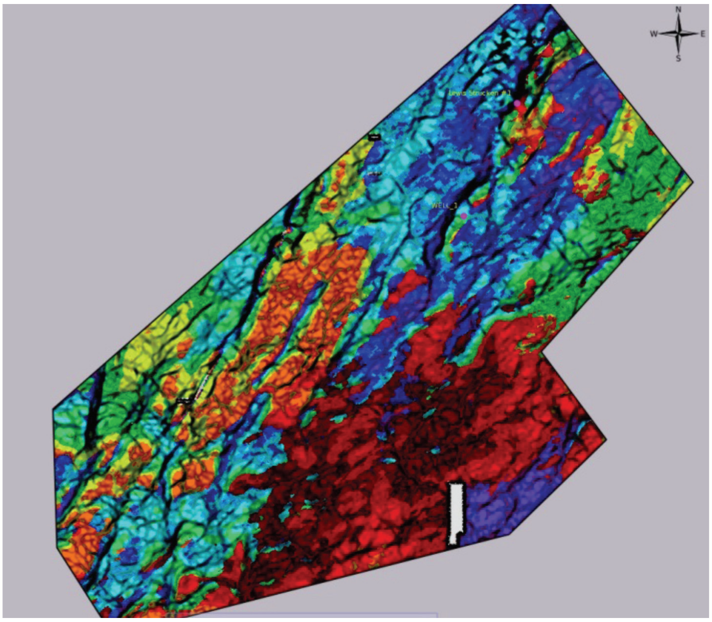

Figure 2. Seismic facies map paired with curvature attribute highlights the heterogeneities of the shale and suggests areas of possible increased fracturing within the Eagle Ford reservoir (Data Courtesy of Seitel)

Interpreting seismic attributes through enhanced visualization, such as advanced merge methods or opacity, layering and interactive cross-plot techniques, provides a more precise reservoir characterization, enhancing predictions of the spatial conditions of trapping systems and the distribution of subsurface lithology and reservoir properties. New, highly parallelized compute power capabilities (GPU – Graphic Processing Unit) to perform computations traditionally handled by CPU power were first adapted for improved visualization as shown in Figure 3. However, they also can be used for on-the-fly calculations to extract post-stack information, such as frequency-dependent attributes, that can efficiently contribute to an interpretation workflow. With proper calibration to *in-situ* conditions observed at the wells, trends can be identified and mapped for sweet spot determination.

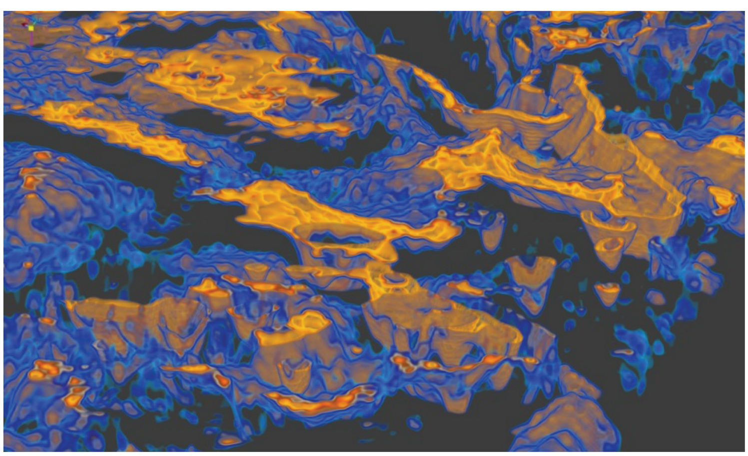

Figure 3. Improved visualization through GPU-based rendering of karsts from the Ellenberger formation in the Barnett Shale

Information from log evaluation (Figure 4) can be used to automatically calculate a predictive model directly, or alternatively can be integrated with the structural interpretation for a more integrated approach.

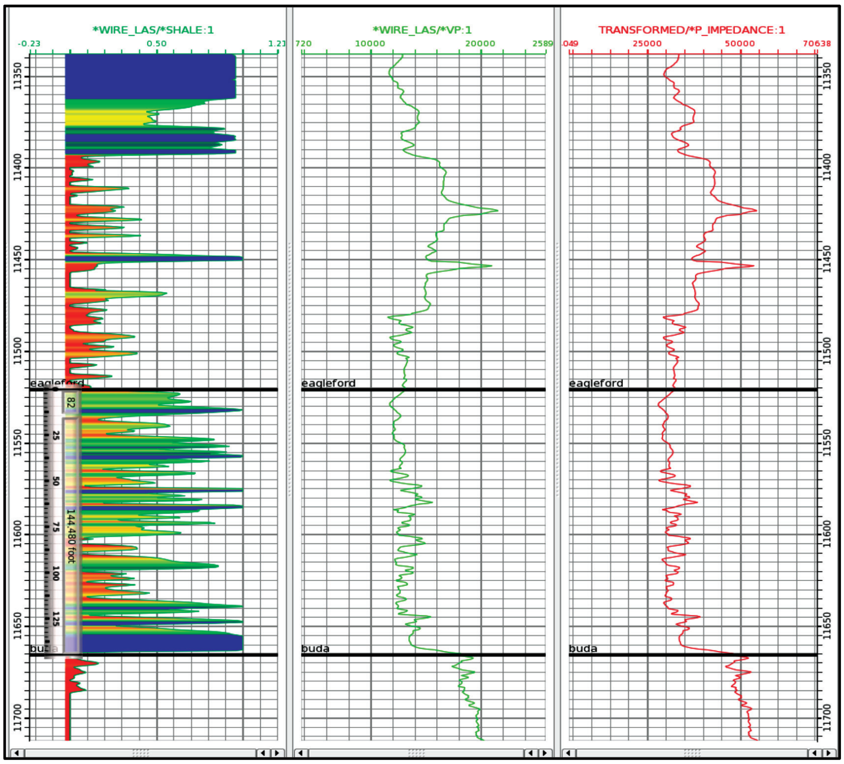

Figure 4. Understanding shale at the wellbore (Eagle ford): A shale thickness of 145 ft, Average P_velocity of 13,000 ft./s and P_Impedance changes to indicate low shale zone.

Unconventional plays have poor reservoir properties and are difficult to interpret on seismic data. This may be due to the negligible acoustic impedance contrast, the presence of gas which degrades P-Wave imaging, or multiple stress episodes. The challenge is even more complex in the presence of faults reactivated after the time of deposition. Proportional reservoir top and base slice extraction is certainly the best approach for understanding the seismic stratigraphy, if the depositional sequence is not complicated by progradation or tectonic events within the interpreted seismic zone. If there is faulting or any internal variation of the sediment depositional sequence, however, this approach will lead to an erroneous geologic interpretation. To avoid such bias, the interpretation should be validated in the paleo-geographic (geochronological) sense at the time of deposition; with a change of reference from X, Y, Z to U, V, T, where T is the geologic time and U, V are the paleo-coordinates. This transform enables paleo-flattening in the UVT space of both the interpretation and the seismic data, and helps the interpreter to better understand the relationship between geological events, and validate the structural interpretation.

The combination of interpretation, characterization and reservoir modeling leads to better control over drilling risk. By integrating all the information in a unique 3D canvas, potential hazards can be identified and mitigated. Using automated, fault-enhanced extraction, the interpreter can extract lineaments along horizontal and vertical slices at the discontinuities (along fault planes) and link them into fault planes. The ability to investigate both the lineaments and the discontinuities associated with them can provide unprecedented insight into potential zones of enhanced fracturing/permeability versus areas of permeability boundaries.

Fracture properties such as density, orientation, dimension and spacing frequently are below seismic resolution, but are needed to create fracture models to simulate the effective permeability at a large scale within the flow simulation grid. As a direct consequence of building a structural model based on the UVT Transform, and respecting the geo-mechanical properties of each facies, a proper workflow should consider the computation of the natural fracture probability in 3D through the generation of structural attributes (stress analysis), and the creation of a stochastic discrete fracture network up to the upscale stage of the fractures to accurately represent the associated porosity and permeability. The integration of all this data to provide reasonable flow simulation results is a powerful QC tool.

The culmination of reservoir characterization, fracture and flow modeling work is the plan for the drilling operations. Rock property attributes that have been extracted in the interpretation phase of the workflow can and should be used to identify not just drilling targets but also potential drilling hazards. The figure below shows areas of karsting within the Barnett Shale that pose potential drilling hazards.

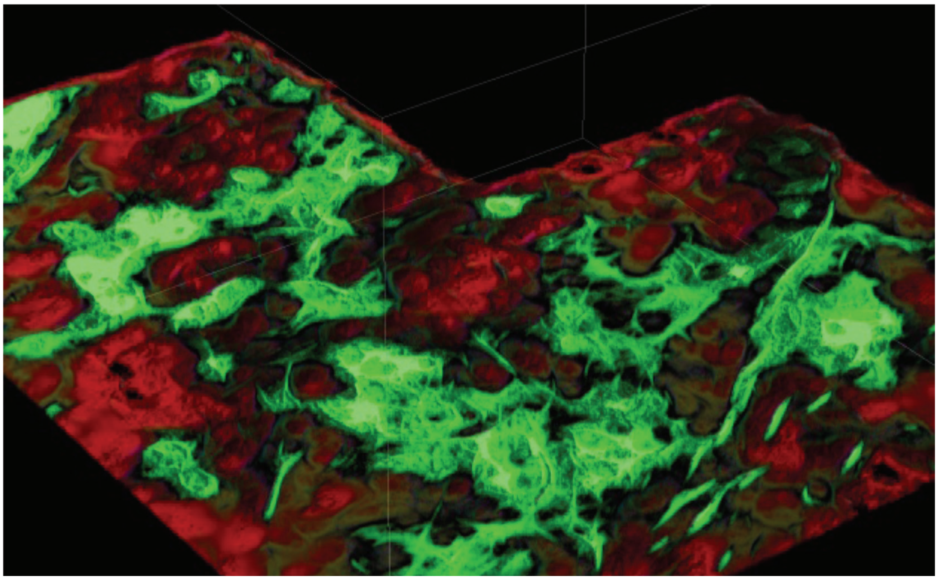

Figure 5. Fault-enhanced attribute shows the impact of faulting and karsts (in green) from the Ellenberger formation that intersects the Barnett to pose fluid-loss hazards.

Workflows to optimally plan these wells are geared towards a fast turnaround. Typically they involve four steps: 1) use of seismic information to locate the seismic horizons associated with the reservoir, 2) integration of the seismic into the geological interpretation, 3) integration of the micro-seismic to define preferential stress directions, and 4) integrated real-time monitoring of the horizontal drilling with interactive correction of the deviation. Understanding in-situ stress regimes and reservoir pressure conditions near the projected well is essential to the success of any hydraulic fracturing program. The resulting microseismic information will then be another source of information to be calibrated with the seismic information in an adapted 3D visualization environment, for time-dependent interpretation of the propagated fractures away from the borehole.

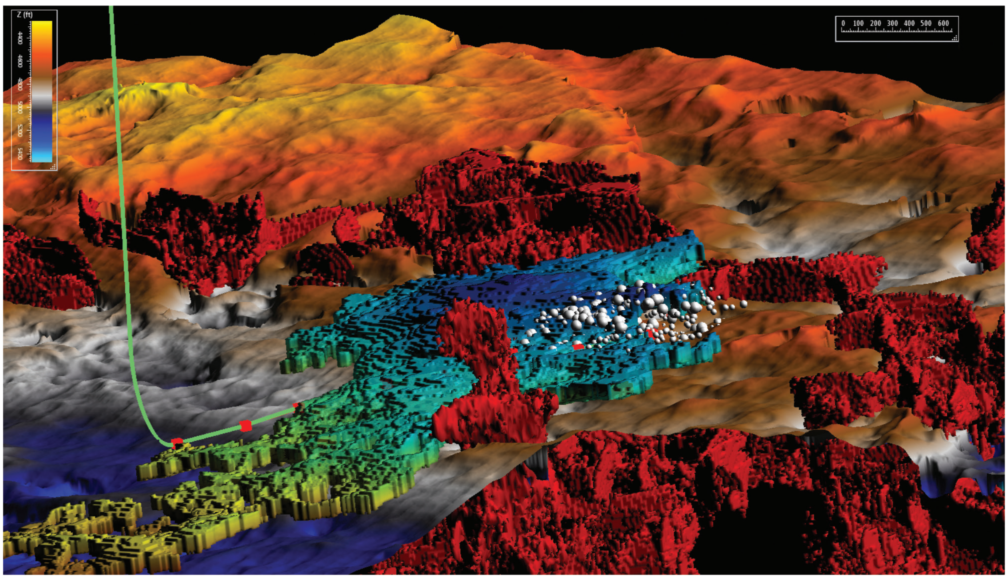

Figure 6. Integration of structural interpretation, karsts and sweet spot 3D geobodies, planned horizontal well with targets.

CONCLUSIONS

Producing hydrocarbons economically from low-permeability unconventional plays drives the need for well path and engineering design optimization at every stage of the planning and drilling process. The subtle nature of fracturing and facies changes in unconventional plays requires the use of rigorous full-azimuth seismic processing, imaging, inversion, interpretation and reservoir modeling. Designing wells within a 3D structural model, which integrates all relevant features, can shorten well planning cycle times, improve well placement and reduce drilling risk, while facilitating the decision-making process.

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