MITIGATE RISK, ENHANCE RECOVERY
Seismically-Constrained Multivariate Analysis Optimizes Development, Increases EUR in Unconventional Plays
As more well and completion data have become available in unconventional U.S. oil and gas plays, geoscientists and engineers have sought to understand exactly which reservoir properties have the greatest impact on production performance in each formation. Over time, operators also have come to depend on seismic data both to map overall structure and to delineate reservoir properties away from well control.

However, it has become painfully clear that strong well performance cannot be correlated with individual reservoir properties in unconventional fields. Instead, a unique combination of various properties and conditions controls the productivity of any particular well or reservoir. With so many post-stack and pre-stack seismic attributes available today (not to mention well logs and engineering information), operators are finding it increasingly difficult to sort through and quantify their meanings, relationships, and relative contributions to reservoir behavior and production results.

Given the fact that there are simply too many static and dynamic variables and potential outcomes for traditional analysis, interpretation and modeling, seismically-constrained multivariate statistical analysis with integrated geoscience and engineering data can provide far more reliable predictive models of cumulative production. A case study from the Wolfcamp Shale play in the Permian Basin shows how operators can apply these models to optimize drilling, completion design and execution, identify refracturing candidates, and ultimately, improve recovery in unconventional wells and fields.

MULTIVARIATE STATISTICAL ANALYSIS

The strength of multivariate statistics lies in its ability to whittle down a potential list of more than 100 attributes from 3-D seismic and well data, and identify the top five or so attributes that have the greatest impact on well performance. The attributes that contribute to cumulative production are known as the well’s key performance indicators (KPIs). Typical KPIs include structural or geometric attributes, attributes related to seismic frequency or amplitude, mechanical and elastic properties, and even completion or engineering attributes such as proppant mass and fluid volume.

KPIs that emerge from multivariate analysis are correlated with other well log, core and completion data to determine which reservoir properties or conditions they may represent. Once these indicators are defined and understood, they can be integrated into a single 3-D predictive model of production.
Figure 1 shows a generic overview of a process dubbed well prospectivity and productivity analysis (WPPA), in which multivariate statistical analysis (orange box in the lower right) plays such a critical role in integrating geological and geophysical data (green boxes) with engineering data (yellow boxes).

**Geoscience data.** The first step is to load and quality control all the available well information needed for production modeling. Primary well data typically consists of well logs for geologic interpretation and petrophysical analysis, wells with velocity control for seismic interpretation and velocity modeling, and horizontal wells with production and completion data. Following the QC of the well information, a rigorous interpretation of the formation tops is performed, making sure the markers are consistently picked at each well.

After defining reservoir zones and surrounding formations, the seismic is tied to the wells using available sonic information. If sonic data are not available, either sonic or density can be estimated from the petrophysics. Obtaining accurate well-ties is essential to further analysis, since any errors that occur at this stage will propagate, causing significant problems later in the workflow.

Following well-ties and error analysis, formation tops, seismic time interpretations, and well velocity control are integrated to build the velocity model. In parallel, a large number of both post-stack and pre-stack seismic attributes are computed. Finally, the integrated velocity model is used to convert all seismic interpretations and attributes from time to depth.

**Engineering data.** The first step on the engineering side of the workflow is to load and QC all relevant deviation surveys, perforation locations, stages, completion and production data. Stage and completion information is used to define productive zones for integration with the geoscience data.
**Geoscience-engineering integration.** The initial step in integrating the geoscience and engineering data is to extract 3-D seismic attributes along each wellbore at or near the stage locations using a statistical sampling method. Next, the extracted attributes are correlated with a range of production metrics, completion data and well data to determine the degree to which variables are correlated. This also allows the interpreter to understand the individual relationships each variable has with production and what type of transformation may be needed in the multivariate analysis.

The goal for this stage is to leverage the integration, allowing the statistics to highlight the meaning of various relationships between production and seismic attributes. The result of multivariate analysis is to identify the KPIs and determine the optimal transformation required for each attribute. Finally, the KPIs are combined to create a 3-D seismically-calibrated predictive model and maps of production (or indeed any other response metric). Based on the input data available, the process also can determine engineering best practices, and facilitate additional steps to validate the models.

The integrated WPPA workflow can be repeated and the models can be carried forward in time throughout the life span of a particular reservoir or field to identify ideal landing points for laterals and completion zones to optimize production.

**PERMIAN BASIN CASE STUDY**

To demonstrate the potential value of multivariate analysis and WPPA technologies, the integrated workflow was applied to predict cumulative production in the Wolfcamp formation in West Texas using a unique dataset consisting of a multiclient 3-D seismic survey and public well and completion data. The objective was to determine if the success of production models created with multivariate analysis and WPPA for more detailed projects elsewhere within the basin and in other unconventional plays could be reproduced using these data inputs.

The 3-D multiclient survey was acquired in 2012, targeting the Permian section of the Wolfcamp. *Figure 2* shows the location of the University Lands 3-D dataset and the major subdivisions of the Permian Basin. The dataset, 356 square miles...
in Reagan, Upton and Crockett counties, covers the eastern edge of the Central Basin Platform and part of the geologically complex Ozona Arch area.

The entire thickness of the Permian section is roughly 4,000 feet, and is shown in color in Figure 2 overlaid on the seismic section. The survey was designed based on a primary depth of 6,000-8,000 feet to allow proper imaging of azimuthal anisotropy. This insured that stable amplitudes within the formation were adequate for interpretation and integration. The survey's dense acquisition geometry also resulted in an uplift in the nominal fold, allowing an increase in the signal-to-noise ratio and providing more robust gathers for future inversion work.

**Seismic attribute analysis.** The seismic attribute analysis began with computing a suite of 45 post-stack seismic attributes, which included a set of incoherence volumes, several fault probability volumes, 15 volumetric curvature attributes, several complex trace attributes, and a set of spectral decomposition frequency volumes. All attributes were analyzed over different intervals within the Wolfcamp section for variations in stratigraphy, thickness, faulting and fracturing, fluid and lateral facies.

From an analytics standpoint, even though the interpreter may be interested only in the reservoir surrounding the producing wells, it is also important to understand how adjacent formations may impact reservoir properties and conditions, and how the seismic data may respond to these changes. Therefore, each seismic attribute was also extracted and analyzed over other horizons and intervals to see how they varied laterally across the University Lands dataset.

**Well-seismic integration.** The next step was integrating the seismic with the well data used for the modeling, which consisted of 21 horizontal wells in the Wolfcamp with production data and limited completion information. In addition, 25 other producing wells were left out of the analysis, reserving them for blind testing to validate or revise predications later on. A single horizontal section was created for the 21 input wells and defined both the completion interval and the interval for the well-to-seismic extractions.

Formation tops and the corresponding time horizons were used with well velocities from two wells to convert all seismic attributes and horizons to depth. The depth-converted seismic attributes were then sampled along the target completion interval and averaged together for the next stage of analysis.

**Geoscience-engineering integration.** The geoscience/engineering integration included individually correlating each attribute with various production metrics to determine the best response or predictor variable for multivariate analysis. We also evaluated how changing these production metrics over time affected the correlations with each attribute. Based on strong linear and nonlinear correlations, three-month oil production scaled per foot of completion length was selected as the variable to predict. Using a nonlinear multivariate regression method, we identified three primary performance indicators out of a wide range of attributes, and tested various transformations of each one.

**KEY PERFORMANCE INDICATORS**

The most important KPIs driving the statistical predictions of three-month oil per foot, along with the reservoir properties or conditions they represented, were:

- Root mean square (RMS) curvature and dip curvature (Kdip). By themselves, these attributes were not highly correlated with cumulative production. However, combined with other variables, they made a significant contribution to well performance. This indicated that structural features associated with faulting and
fracturing, seals and migration pathways were impacting production.

- Relative amplitude change and 24-28 hertz spectral decomposition frequency volumes. We used these attributes interchangeably, since relative amplitude change had a high linear relationship with mid-frequency volumes. The lower values of relative amplitude change indicated an increase in both water and oil production, which was verified with hydrocarbon and water saturation logs in several wells across the field. Significantly higher fracture porosity in these zones of higher fluid saturation was also noticed.

- 10-14 Hz spectral decomposition volumes. Low-frequency spectral decomposition attributes correlated with both total organic carbon (TOC) and the brittle/ductile quality that was calculated at several wells. Correlations of nine-month gas production versus low-frequency volumes also supported this relationship. As the 10-14 Hz component increased, so did both gas production and TOC.

Next, these top performance drivers were modeled to production using the optimal transformations for each, which were then summed to form the production prediction for various models. Using no more than three seismic attributes for each model, three unique 3-D models of three-month oil per foot were generated. The same extraction parameters were then used to extract the predictions along each wellbore. The average correlation coefficient (CC) between actual versus predicted production for the three models was 92 percent for the 21 input wells (left panel in Figure 3).

To test how effectively the model could predict cumulative production performance, the 25 producing wells that had been excluded from the modeling workflow were then introduced. Adding actual versus predicted production from 17 blind horizontal wells and eight blind vertical wells with single-zone completions to the 21 input wells achieved a correlation coefficient of 83 percent (right panel in Figure 3). Looking only at the eight vertical wells, the model showed a 90 percent correlation between predicted and actual production. These high correlations demonstrate the predictive power of multivariate statistical analysis and the impact it can have on unconventional field development.

![Figure 3: The crossplot on the left shows the relationship between the predicted vs. actual production for the 21 input wells. The crossplot on the right shows the relationship between the input and blind wells vs. actual production.](image)
The decision was then made to examine the possibility of refracturing some or all of the existing vertical wells in specific zones where the model indicated high production potential. This was accomplished by comparing the ratio of production from the entire Wolfcamp zone with production extracted at the actual perforation locations. According to the analysis, three of the eight vertical wells with single-zone completions had potential zones of high production not accessed by the original completions.

Figure 4 displays an arbitrary cross-section through six of the eight vertical wells. The log displayed in color is the extracted production model along the vertical wells. The red disks show the actual completion interval for these wells. Wells 1, 3, and 4 (highlighted in yellow) have the highest probability for refrac success.

Looking at the models in 3-D showed how much lateral variability exists between these wells in the target interval. Figure 5 shows an arbitrary line through vertical wells 1, 3, and 6 from Figure 4. Note the lateral variations of the production prediction model. The seismic in the background is co-rendered with the fault probability, with the production ribbon displayed in color over the reservoir zone.
The best vertical producer in the survey area—well 6 shown at the left in Figures 4 and 5—had 10,700 barrels of actual production over three months versus a predicted production of 10,900 barrels (98 percent accurate). Well 3 had 2,090 barrels of actual versus 2,300 barrels of predicted production. Well 1 was one of the poorer performers. It produced 101 barrels, and its predicted production was roughly the same. However, wells 1 and 3 have the highest probability for refracturing success, because the completions in both wells missed the sweet spot revealed by multivariate analysis and predictive modeling. Targeting these zones, each well should be able to generate three-month production values of about 10,000 barrels. It should be remembered that neither of these wells were used in the initial modeling.

This Permian Basin case study clearly demonstrates the potential value of using WPPA workflows to improve well planning, optimize completions, and enhance recovery, even without a full suite of data.

THE BOTTOM LINE

The productivity of any well is a function of the interplay among many static and dynamic characteristics that require an integrated, multivariable solution. The WPPA workflow represents a sophisticated multidisciplinary integration of the geophysical, geological and engineering data. By combining numerous diverse sets of data, geoscientists and engineers can identify the specific attributes essential to hydrocarbon production in a particular reservoir. Not only can they generate quantitative estimates of the values that impact production, but they also can identify the most prospective areas for drilling. Properly applied, this workflow can significantly reduce drilling risk and improve drilling programs.

The Wolfcamp case study emphasizes the value that multivariate statistical analysis of 3-D seismic, well and engineering data can bring to unconventional reservoirs. The 3-D seismic attributes applied in the Permian Basin can predict well performance down to the stage level. Similar results have been obtained in successful projects in both conventional and unconventional reservoirs across North America. Results achieved in the field have proven that WPPA models can high-grade prospective drilling areas, enhance well planning and geosteering, optimize completion placement and frac design, and boost the estimated ultimate recoveries of individual wells.

To learn more about this solution and how it is being applied to help operators optimize development and increase EUR in unconventional and conventional plays, please contact us at analytics@globalgeophysical.com or visit globalgeophysical.com/analytics.

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