Seismic Data Key For Flow Simulation

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HOUSTON–Designing horizontal wells and hydraulic fracture stimulation in unconventional reservoir requires a detailed understanding of the variations in matrix and fracture properties. Matrix properties control not only the volume of hydrocarbons and the ability of the rock to fracture under hydraulic stress, but also determine how effectively the hydrocarbons can flow from the matrix to the fracture network.

Natural fracture properties are responsible for the effectiveness and penetration into the formation of the hydraulically connected network of new or reactivated fractures that result from stimulation. Understanding local stress field variations also is an essential part of the equation for the success of hydraulic stimulation projects.

However, no matter how good earth scientists and engineers think their understanding of the static components of the system is, static models of unconventional reservoirs should be calibrated, validated and constrained with dynamic reservoir data before reliable production forecasts can be made.

For this reason, flow simulation is a critical component in characterizing unconventional reservoirs because it helps to ensure consistency between static and dynamic data, and because flow simulation is the only way to take into account all the complex interactions between geologic properties and fluid behavior that determine the nature of the production decline and well interference.

Flow simulation models require information about the reservoir variables that can affect both storage and deliverability. Seismic-derived information can help constrain critical parameters in flow simulation models such as the porosity and permeability of matrix and fractures in unconventional reservoirs. However, for seismic-derived information to be useful for flow simulation models, it must be "translated" into variables that directly affect the two main parameters of storage and deliverability.

A workflow has been developed to use seismic to generate of both matrix and natural fracture models that describe storage and deliverability in unconventional reservoirs, and constrain flow simulation models. The process starts by careful facies definition based on production drivers. The facies are carried throughout the entire workflow, ending with facies modeling constrained by seismic derived-facies probabilities.

The workflow consists of three steps: matrix characterization, fracture characterization, and flow simulation. Matrix characterization begins with facies definition, where the critical production drivers (porosity, brittleness, natural fractures, etc.) are related to rock types at log-scale and rock physics diagnostics are made. Seismic calibration and mapping are then performed for facies and fracture properties, where seismic data are trained at well locations and the results are applied to the entire area. Matrix and fracture properties are integrated consistently with geological, petrophysical and engineering data to generate static matrix and fracture models.

The final step is flow simulation, where the effective stimulated rock volume can be estimated/calibrated with geologic matrix-fracture models, microseismic data, hydraulic fracture conductivities, and well performance.

Matrix Characterization

An adequate and consistent facies definition is essential for the workflow's success, not only because facies indicate whether a rock will fracture under hydraulic stress (brittleness), but also because they control the porosity and permeability distribution across the model as well as the variability and intensity of existing natural fractures relative to faults.

Production drivers should be considered while defining facies that will also be carried through flow simulation. For this reason, geological facies derived from core descriptions alone may not necessarily be adequate to build geological models that end in flow simulation. Another disadvantage of core-based geologic facies is that they may not separate well in

FIGURE 1

Facies Definition using Neutron-Density Cross-Plot

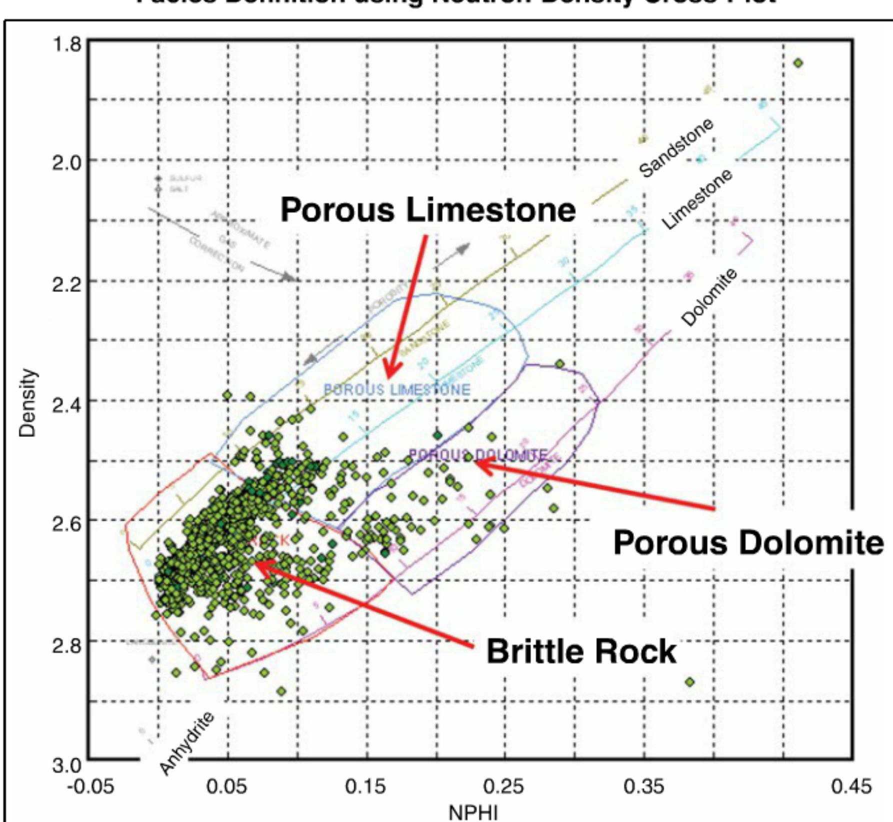


FIGURE 2

Brittle Lithofacies Based on FMI Data (Left) versus Dipole Sonic (Right)

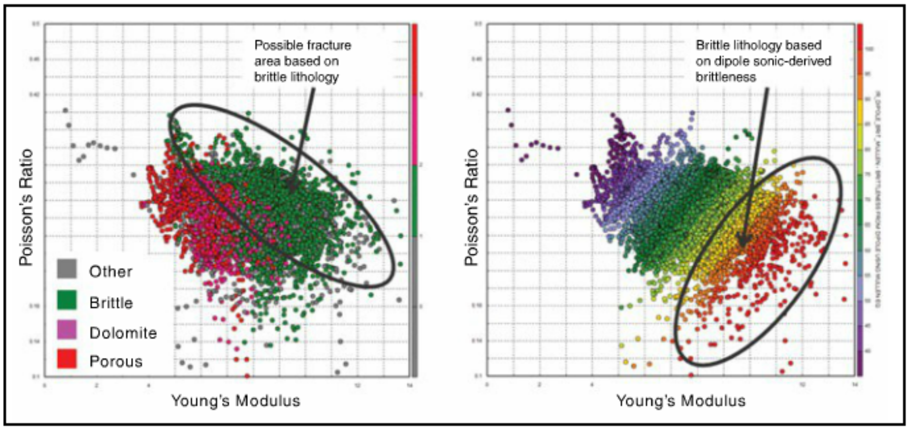


FIGURE 3

Geostatistical Facies Modeling using Seismic-Derived Information

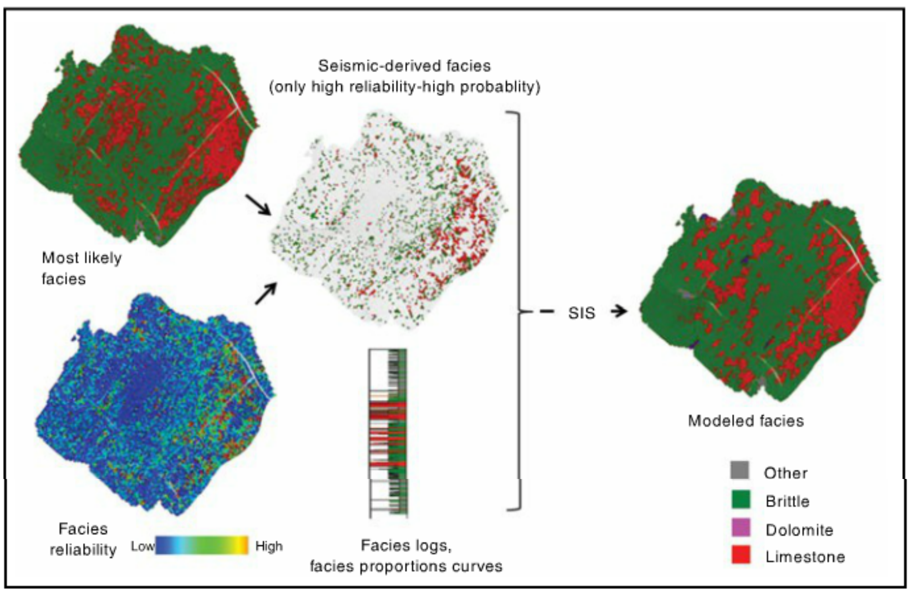
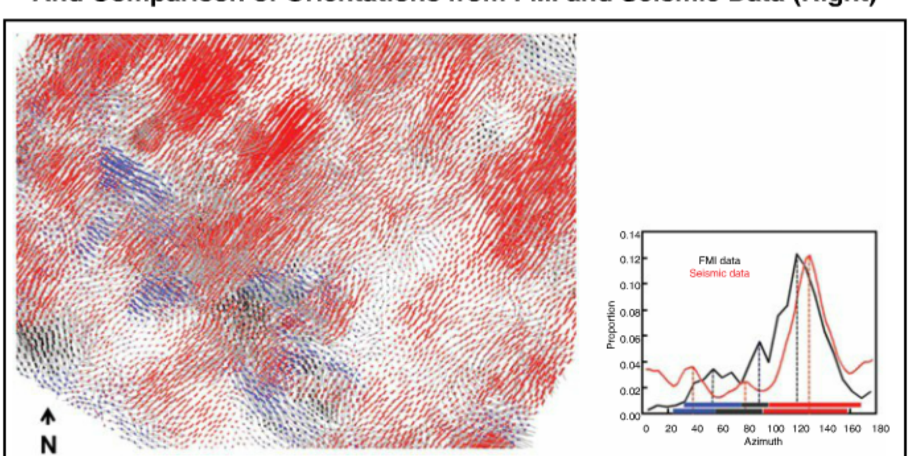


FIGURE 4

Local Orientations and Intensities of Fracture Families (Left) And Comparison of Orientations from FMI and Seismic Data (Right)



cross-plots of elastic properties, which can hinder using seismic data to guide facies mapping.

If facies are defined without "human intervention," using only statistical methods such as multivariate cluster analysis from log or seismic data, their consistency should be checked from log- to seismic-scale as well as their relationships to the actual production drivers that control flow behavior.

If natural fracture information is available, it should be used when defining facies. Figure 1 shows an example of facies definition using a neutron-density cross-plot. Only points that correspond to conductive or partially conductive fractures from formation microimaging (FMI) data are plotted. Notice that most observed natural fractures in the image occur in lower-porosity intervals and these rocks are called "brittle." Other rocks with considerably fewer or no fractures are called "porous" in this example.

However, the brittle facies defined by the presence of fractures do not necessarily coincide with rocks with the highest brittleness coefficient estimated from dipole sonic data. For this reason, a careful calibration with log data is important to understand the actual relations between defined facies and production drivers in unconventional reservoirs. As an example, Figure 2 shows a comparison of brittle lithofacies based on FMI data (left) versus brittle rock from brittleness derived from dipole sonic (right).

Once facies have been defined and rock physics analysis shows that they can be mapped spatially using elastic properties derived from seismic prestack inversion, different methods can be used to estimate facies probabilities across the reservoir. Most probabilistic approaches to map facies using seismic data are based on an approach to statistical rock physics for reservoir characterization proposed by Stanford University professor Tapan Mukerji, et. al. (2001). This approach requires probability density function modeling on cross-plots of elastic properties at log scale colored by facies.

Unlike the common implementation of the Mukerji approach, the new workflow works on cross-plots of inverted attributes at seismic scale, and yields not only estimates of the spatial variability of facies probabilities, but also estimates of reliability of such probabilities (even in cases when there is total overlap between the target facie and the background in cross-plots of inverted attributes).

Figure 3 shows how seismic-derived facies can be used to constrain geostatistical facies modeling using only the seismic facies considered both more likely and more reliable as hard constraints. The most reliable/likely facies from seismic, along with facies logs and facies proportion curves, are used to generate facies models based on geostatistical simulations. Finally, matrix porosity and permeability are estimated for each facie using core data. Permeability (for matrix and fractures) is then calibrated using production data.

Fracture Characterization

For the fracture characterization part of the workflow, local gradients are computed from post-stack structural attributes, and circular statistical analyses are performed in moving superbins. Global histograms of fracture orientations in the area of interest can help to identify a dominant family of fractures, while local, filtered histograms extracted from the superbins can help identify additional fracture families that may be immersed in more random, regional fracturing.

Figure 4 (left) shows a map of local orientations and relative intensities of fracture families that result from local statistical analyses. Different fracture families may be present in the same area, since no assumption is made about the number of families or their relative orientations. Individual families in each superbin are described by their dominant orientation, dispersion (Fisher coefficient), and count (intensity), and this information is used to constrain continuous or discrete fracture network (DFN) models. In this case, the dominant family is indicated in red, but two other less important families (blue and black) also can be identified, with more random fractures indicated in gray in the background.

Fracture properties that control fluid flow such as aperture or aspect ratio may vary for different families in the fracture models. A proxy for permeability anisotropy in the flow simulator can be obtained by assigning different permeabilities to different fracture families, or by using the Fisher coefficient.

On the right-hand side of Figure 4, the orientation of natural fractures interpreted from FMI data are compared with orientations derived from local statistics of angles. The relative intensities and orientations of the red, blue and black families estimated from seismic data are similar to those observed from well data (the difference between the dominant orientations per family from seismic and FMI data varies between 9 and 17 degrees). The seismic-derived histogram has been rescaled to match the scaling of the FMI fracture counts.

Figure 5 shows the seismic-derived attributes used to constrain the DFN modeling for the locally dominant fracture orientation. DFN models then are used to estimate a variety of fracture parameters such as permeability anisotropy, aperture, intensity, connectivity and surface area, which need to be calibrated in the flow simulation step using production data. Areas highlighted in red show similar intensity and orientation, but different Fisher coefficients (therefore, modeled fractures in these areas also show different orientation dispersions).

Flow Simulation

Flow simulation is an important task for constraining the seismic-based matrix

FIGURE 5

Seismic-Derived Attributes to Constrain DFN Modeling Using Dominant Local Fracture Orientation

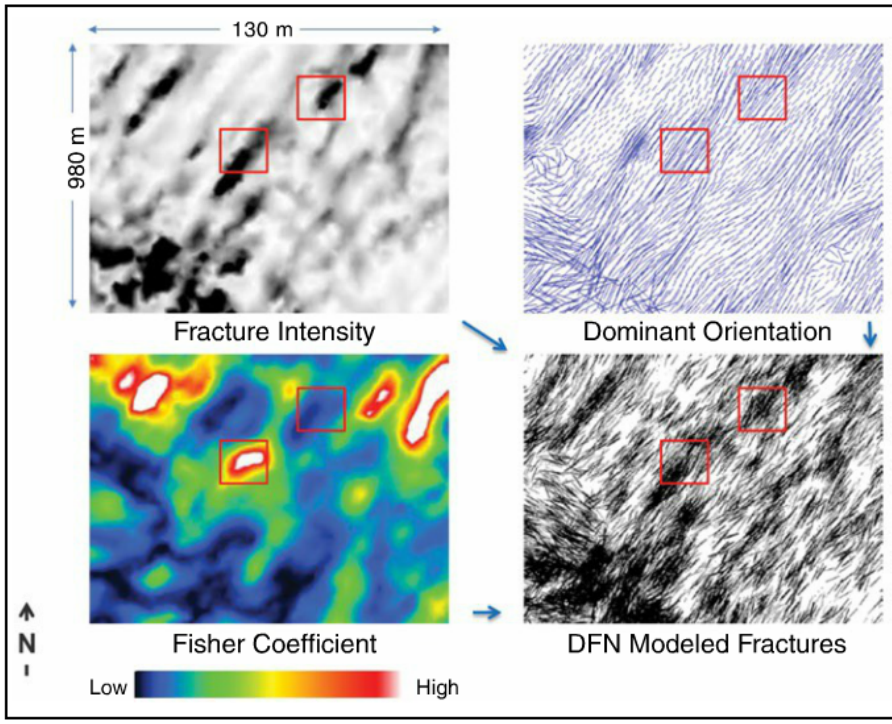
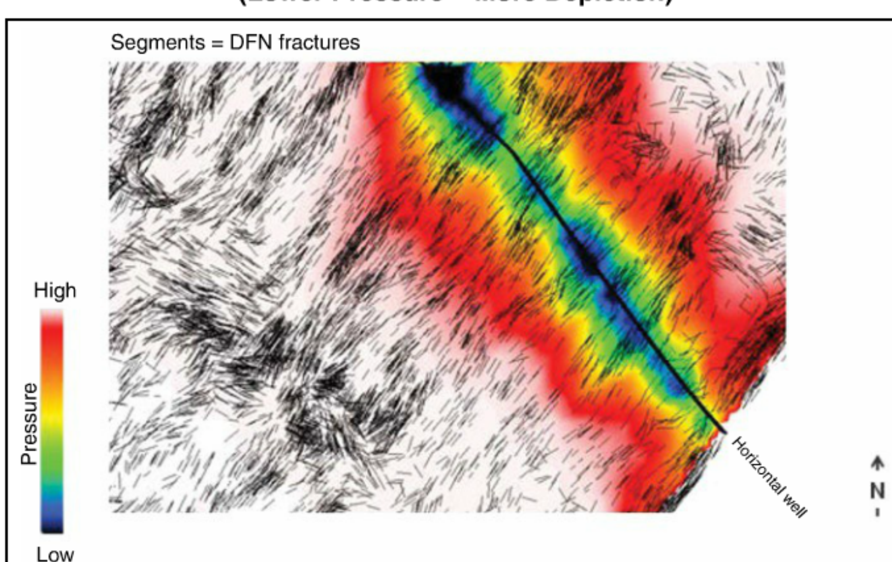


FIGURE 6

Simulated Pressure after 100 Days of Production (Lower Pressure = More Depletion)



and fracture characterizations, and for testing the impact on long-term well performance. The matrix attributes mapped to the simulation grid and used to constrain the flow simulation are dominant facies, porosity and permeability. The fracture attributes per family are dominant orientation, Fisher coefficient and intensity. Distance to faults also is used to weight the fracture intensity relative to facies (brittle facies tend to fracture more than porous facies near faults).

Fracture attributes then are used to derive production-constrained directional permeability, porosity and fracture-matrix surface area using discrete or continuous fracture modeling. Fracture attributes are used to derive production constrained directional permeability, porosity and fracture-matrix surface area through discrete or continuous fracture modeling (see Dershowitz, et. al., SPE paper 49069, and Gilman, et. al., SPE paper 146580). Understanding natural fractures is obviously important for optimizing completions and well spacing.

Figure 6 shows how the pressure field (depletion) generated from flow simulation varies along the well path using simulated field pressure after 100 days of production. This variability is a function of matrix properties (porosity and matrix permeability) and natural fracture intensity near the wellbore. Areas with a higher intensity of natural fractures tend to deplete faster than areas of lower intensity in this example (lower pressure is related to more depletion). A constant 5X permeability enhancement was applied in the model to simulate hydraulic fracturing with a 150-foot effective stimulated radius.

Beyond the traditional use of seismic data to map "the container" in reservoir models, seismic data can help constrain matrix and fracture models calibrated using flow simulation. Advances in fracture mapping from post-stack structural seismic attributes are generating better-constrained fracture models that include fracture orientations, intensities and dispersion (Fisher coefficient) per fracture set. Consistency between static and dynamic data increases confidence in long-term production forecasts, helping to optimize development.

Critical Dimension

Even though enormous progress has been made in using seismic to constrain flow simulation models, there is still a long way to go before all the data available in unconventional reservoirs can be integrated fully. Microseismic data acquired during stimulation will add another critical dimension to calibrating seismic results and estimating stimulated rock volumes from flow simulation.

We do anticipate using more microseismic data to calibrate results from 3-D seismic, continuous and DFN models, and flow simulation predictions. Instead of the usual practice of using a constant permeability enhancement near the wellbore to simulate hydraulic fracturing in flow simulation, for instance, we may use the variable density of microseismic events along the well path to iteratively constrain the effective stimulated rock volume. Faster simulators also will allow preserving more details of the original geological model, and allow running more cases to test sensitivities and calibrate with historical production data.

Moment tensor inversion of microseismic data will be used to better calibrate orientations in fracture models along with orientations from image logs and 3-D conventional/3-C seismic data. The joint use of microseismic data and 3-D seismic data will help design future horizontal wells based on information recorded on existing wells.

More research is needed to understand the relation between data-driven approaches to characterize natural fractures from statistical analyses (from post-stack-derived orientations) and model-driven approaches based on estimating azimuthal velocity anisotropy (from azimuthal amplitude-variation-with-offset or birefringence analysis of 3-C data) in cases where multiple families with different orientations and dips are present. These approaches are complementary, and both should be used and compared whenever possible. Data-driven approaches based on structural attributes may fail in areas where the presence of natural fractures is not related to faulting.

In any case, careful data analyses, more data integration, local calibration and consistency among different data types will remain the keys to unlocking the difficulties of unconventional reservoirs. ❐

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