Flow simulation models for unconventional reservoirs: the role of seismic data

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Summary

We describe in this paper how seismic derived information can help to constrain critical parameters in flow simulation models such as porosity and permeability of matrix and fractures in unconventional reservoirs. The process starts by careful facies definition based on production drivers. These facies are then carried through the whole workflow that ends on facies modeling constrained by seismic derived facies probabilities. Recent advances in fracture mapping from poststack structural seismic attributes have helped to generate better constrained fracture models that include fracture orientations, intensities and dispersion (Fisher coefficient) per fracture set. Matrix and fracture models are tested and calibrated by using production data and flow simulation models. Even though enormous progress has been made in using seismic data to constrain flow simulation models, we anticipate that the use of microseismic data will add another critical dimension into the calibration of seismic results and estimation of stimulated rock volumes from flow simulation.

Introduction

The design of 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 how effectively these hydrocarbons can flow from the matrix to the fracture network. Natural fractures 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 of local stress field variations is also an essential part of the equation for success of hydraulic stimulation projects. However, no matter how good we think our 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 the characterization of unconventional reservoirs because it helps to ensure consistency between static and dynamic data and 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.

Flow simulation models require information about the reservoir variables that can affect both storage and deliverability. Therefore, for seismic derived information to be useful for flow simulation models it needs to be "translated" into variables that directly affect these two main parameters. We show in this paper how seismic data can contribute to the generation of both matrix and natural fracture models that describe storage and deliverability in unconventional reservoirs and how this information can be used to constrain flow simulation models.

General workflow

Our workflow consists of three steps: matrix characterization, fracture characterization, and flow simulation. The matrix characterization starts by facies definition, where the critical productions drivers (porosity, brittleness, natural fractures, etc.) are related to rock types at log scale and rock physics diagnostics are made. Then, we do seismic calibration and mapping for facies and fracture properties where seismic data is trained at well locations and the results are applied to the whole area. Matrix and fracture properties and integrated consistently with geological, petrophysical and engineering data to generate static matrix and fracture models. Finally we do flow simulation, where 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 success of the workflow 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 up in flow simulation. Another disadvantage of core based geologic facies is that they may not separate well in crossplots of elastic properties which can hinder the use of 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, we should check their consistency from log to seismic scale as well as their relation with actual the production drivers that control the flow behavior.

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If natural fracture information is available, it should be used when defining facies as shown in Figure 1. Notice that most observed natural fractures occur in lower porosity intervals and we call these rocks "brittle". Other rocks with considerably fewer or no fractures are called "porous" in this example. Notice, however, that "brittle" facies defined by the presence of fractures do not necessarily coincide with rocks with highest "brittleness" coefficient estimated from dipole sonic data as shown in Figure 2. 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.

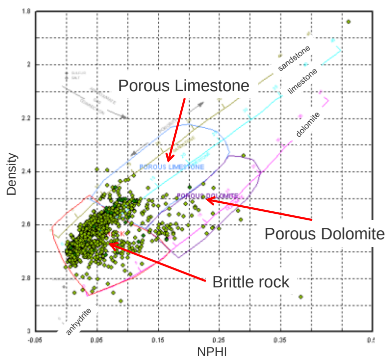

Figure 1: Facies definition using Neutron-Density crossplot. Only points that correspond to conductive or partially conductive fractures from FMI data are plotted. Rocks with highest presence of natural fractures are called "Brittle" and rocks with less fracturing and higher porosity are called "Porous".

Once facies have been defined and rock physics analysis shows that they can be spatially mapped using elastic properties derived from seismic pre-stack inversion, we can use different methods to estimate facies probabilities across the reservoir. Most probabilistic approaches to map facies using seismic data are based on the classic paper by Mukerji et al. (2001) on statistical rock physics for reservoir characterization. This approach requires probability density function modeling on crossplots of elastic properties at log scale colored by facies. Unlike the most common implementation of Mukerji's et al. approach, our approach works on crossplots of inverted attributes at seismic scale (Michelena et al., 2011) and yields not only estimates of the spatial variability of facies probabilities but also estimates of reliability of such probabilities. Figure 3 shows how seismic derived facies can be used to constrain geostatistical facies modeling by using only the seismic facies that are considered both more likely and more reliable. The most reliable/likely facies from seismic are used as hard data along with facies logs and facies proportion curves to generate facies models based on geostatistical simulations (Sequential Indicator Simulation in this case). Finally, matrix porosity and permeability are estimated for each facie using core data, and permeability (for matrix and fractures) is then calibrated by using production data.

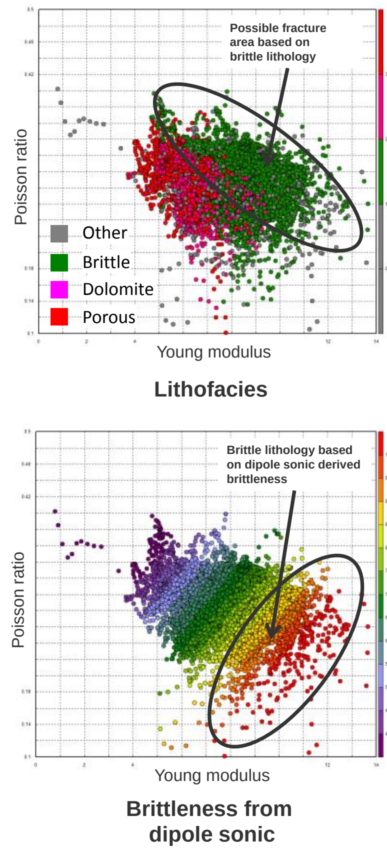

Figure 2: Comparison of brittle lithofacies based on FMI data (above) vs. brittle rock from brittleness derived from dipole sonic (below). The two estimates do not necessarily coincide.

Fracture characterization

For the fracture characterization part of the workflow, we compute local gradients from poststack structural attributes and perform circular statistical analyses in moving superbins. Global histograms of fracture orientations in the area of interest can help to identify a dominant family of fractures whereas local, filtered histograms extracted from the superbins can help identify additional fracture families that may be immersed in a more random, regional fracturing (Figure 4). Then, we describe individual families in each superbin (Figure 5) by extracting their dominant orientation, dispersion (Fisher coefficient), and count (intensity), and use this information to constrain continuous

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or discrete fracture network (DFN) models. Fracture properties that control fluid flow such as aperture or aspect ratio may vary for different families in the DFN model. Figure 6 compares orientation of natural fractures interpreted from FMI data versus orientations derived from local statistics of angles from structural attributes. The difference between the dominant orientations per family from seismic and FMI data varies between 9 and 17 degrees in this example.

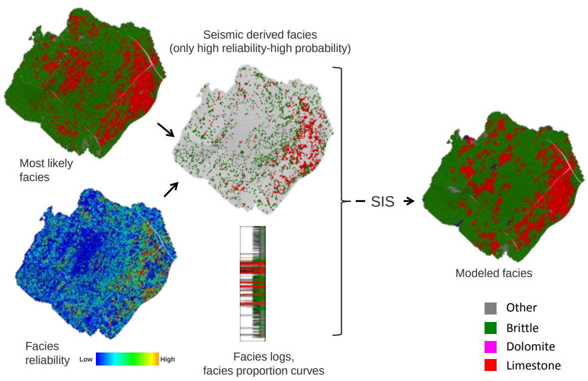

Figure 3: Geostatistical facies modeling using facies information derived from seismic. Only the most likely and reliable facies are used as hard constraints along with log facies flags and facies proportion curves. Sequential Indicator Simulation (SIS) was used in this case to generate facies models.

Figure 7 shows the seismic attributes that are used to constrain the DFN modeling for the locally dominant fracture orientation. DFN models are then used to estimate permeability anisotropy and to set other fracture related parameters such as aperture, intensity, and connectivity which need to be calibrated in the flow simulation step.

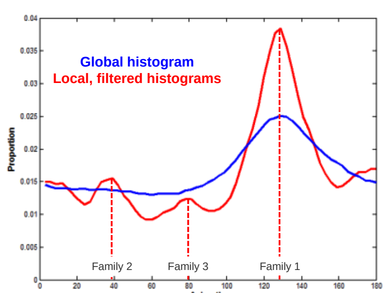

Figure 4: Orientations derived from gradients extracted from structural attributes. Blue: histogram of original angles from the whole area of interest; only the dominant family of fractures is visible. Red: histogram from the analysis of peaks in local, filtered angle histograms; other families of fractures can be detected.

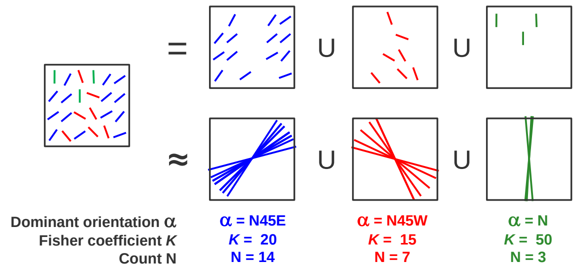

Figure 5: Statistical analysis of orientations in moving superbins can help to separate different fracture families. For each superbin in the seismic volume, we estimate dominant orientation, Fisher coefficient, and count for each family of natural fractures. This information is then assigned to the center of each superbin.

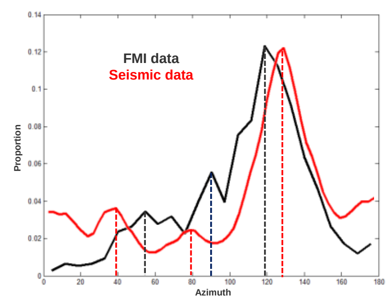

Figure 6: Comparison of fracture orientations from FMI data and seismic data. Dominant orientations per family estimated from seismic data are close to those estimated from FMI data. Relative intensities of families 1 and 2 from seismic data are similar to the intensities from well data. The seismic derived histogram has been rescaled to match the scaling of the FMI fracture counts.

Flow simulation

The attributes mapped to the simulation grid and used to constrain the flow simulation are dominant facies, porosity, permeability, and fracture properties per family such as dominant orientation, Fisher coefficient (which is a proxy for permeability anisotropy) and intensity. Distance to faults is also used to weight the fracture intensity relative to facies (brittle facies tend to fracture more than porous facies near faults). As Figure 8 shows, the pressure field (depletion) varies along the well path and this variability is a function of matrix properties (porosity and matrix permeability) as well as the natural fracture intensity near the wellbore: areas with higher intensity of natural fractures tend to deplete faster than areas of lower intensity.

The road ahead

Beyond the traditional use of seismic data to map "the container" in reservoir models, we have shown that, after careful calibration, seismic data can help constrain matrix and fracture models that can be tested with production data

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flow simulation. Consistency between static and dynamic data helps increase confidence in long-term production forecasts. However, we still have a long way to go before we fully integrate all the data available in unconventional reservoirs.

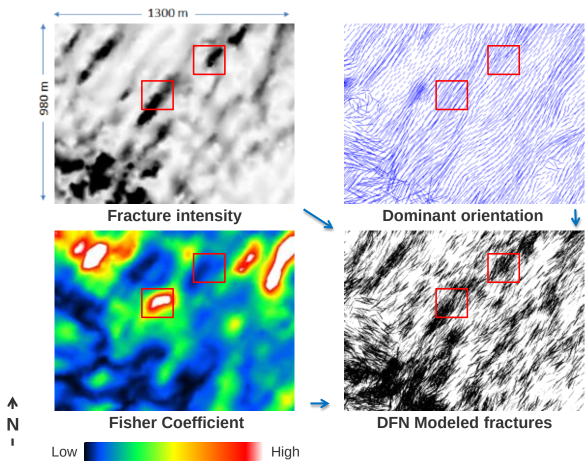

Figure 7: Seismic derived attributes used to constrain DFN modeling using the dominant local orientation. Areas highlighted in red show similar intensity and orientation but different Fisher coefficient and therefore, modeled fractures in these areas also show different orientation dispersion. For details about the estimation of the Fisher coefficient from seismic data see Michelena et al. (2013).

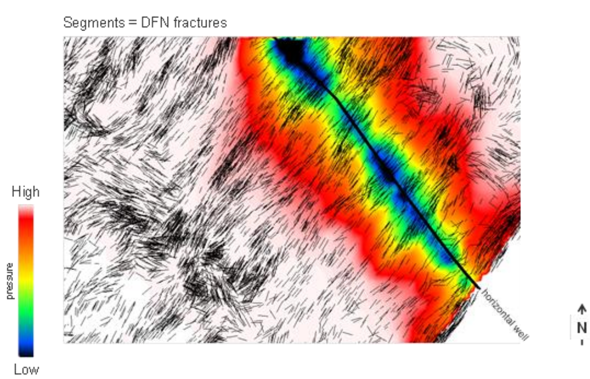

Figure 8: Simulated pressure field after 100 days of production. Lower pressure is related to more depletion. Areas with higher intensity of natural fractures tend to deplete faster than areas of lower intensity. Overall variability in pressure field depends on both matrix and fracture permeability. A constant 5X permeability enhancement was applied in the model to simulate hydraulic fracturing with 150 ft. effective stimulated radius.

Unconventional reservoirs are often monitored with microseismic arrays while stimulation is being performed. We anticipate more use of microseismic data to calibrate results from 3D seismic, continuous and DFN models, and flow simulation predictions. Figure 9, for instance, shows that the density of microseismic events mapped to the simulation grid may also be variable along the well path. We propose that this information should also be used to iteratively constrain flow simulation and estimate the effective stimulated rock volume in unconventional reservoirs to improve on the usual practice of using a constant permeability enhancement near the wellbore to simulate hydraulic fracturing. Faster simulators will also allow preserving more details of the original geological model and running more cases to test sensitivities.

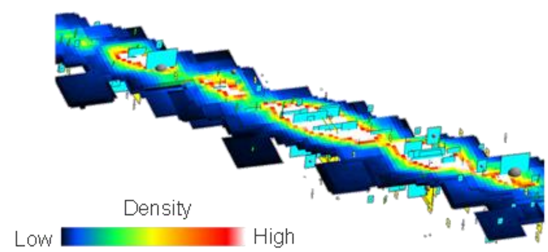

Figure 9: Density of microseismic events along well path. Similar to pressure field in Figure 8, variability in density of microseismic events is also affected by matrix and fracture properties.

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

More research is also needed to understand the relation between data driven approaches to characterize natural fractures from statistical analyses (from poststack derived orientations) and model driven approaches based on the estimation of azimuthal velocity anisotropy (from azimuthal AVO or birefringence analysis of 3C data) in cases where multiple families with different orientations and dips are present. We believe that 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, more data integration, local calibration and consistency among different data types will remain as the key to unlock the difficulties of unconventional reservoirs.

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EDITED REFERENCES

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