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Developing unconventional reservoirs using limited natural fractures statistics – challenges and opportunities

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Introduction

While reading Ellenberg (2015) book "*How Not to Be Wrong: The Power of Mathematical Thinking*", the story of Abraham Wald and his efforts during WWII to help the Navy armor its planes was a good analogy to explain the challenges of natural fracture statistics.

Armoring a plane to protect it against bullets means an increase in weight thus limiting the plane capabilities. As a result, one must limit the armoring to minimum strategic areas. To find the areas that needed additional armoring, the Navy studied the statistical distribution of the damage observed in its planes and concluded that the wingtips, the central body, and the elevators are the areas to focus on (Figure 1). Abraham Wald, a statistician, disagreed with the Navy and proposed to armor the nose area, engines, and mid-body which are not damaged areas in Figure 1**.** Abraham Wald was not fooled by the misleading statistics shown by Figure 1 and realized that the planes were getting shot in the nose, engines and mid-body, but they weren't making it back home therefore were not contributing to the statistics shown in Figure 1. This survivorship bias highlights the ever-present issue of sampling bias which affects all geologic inquiries, especially the statistics of natural fractures.

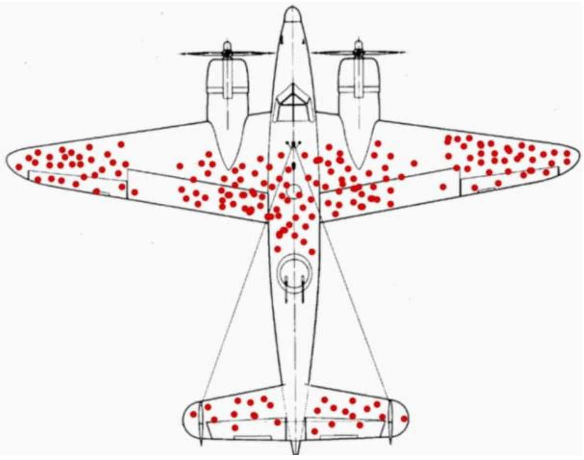


Figure 1: Statistics of damage observed by the Navy used to decide where to armor their WWII planes. Abraham Wald disagreed and suggested to armor the nose, engines and mid-body because the planes shot in these areas crashed and did not contribute to the flawed statistics.

Engineers in the oil and gas industry have been dealing with problems of statistical sampling since the late 80's when statistics was introduced to improve reservoir models and the resulting fluid flow in heterogenous rocks. These statistically driven and more realistic geologic models represented a departure from simple layer cake models with constant rock properties. The contribution of geostatistics has dramatically improved the modeling of conventional rock properties such as porosity which improved the ability to better predict the multiphase flow in oil and gas reservoirs. One reason behind the success of the geostatistics on rock properties such as porosity is the availability of a statistically significant number of wireline logs at the wells that provide an estimation of these properties. Additionally, porosity tend to follow a Gaussian distribution which contributed to the success of geostatistics that uses many algorithms that work better when the modeled data follow such a commonly found and simple distribution. Once porosity was correctly estimated, complex properties such as permeability were estimated with simple methods (k-phi transform) or more complicated methods such as cloud transform. Unfortunately, the situation is more complex for naturally fractured reservoirs which are known to have log normal distributions and a myriad of sampling challenges.

The challenge of natural fractures and their statistics

The distribution of natural fractures at any scale tends to be log normal and the oil and gas industry does not drill wells specifically to acquire information about the statistics of natural fractures. From time to time, an image log is acquired in a well or in some rare occasions a core is taken at a so called "science wells" and may survive the coring procedure to reveal its natural fractures and their multiple manifestations (Lorenz and Cooper, 2017). Unfortunately, the probability to intercept fractures with wells is very low especially when they are vertical as shown in Figure 2 (Lorenz, 1992). Using horizontal wells, could increase this probability if the horizontal well azimuth is designed to cross the various natural fractures sets but that's not always the case. Cores and images logs in horizontal wells remain rare and when available they may not capture all the natural fractures statistics. This problem has major implications for the development of unconventional reservoirs as will be illustrated with an example from the Hydraulic Fracturing Test Site I industry consortium (HFTS-1).

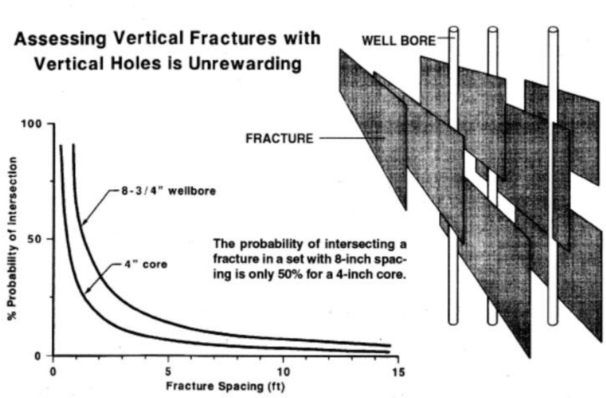


Figure 2: When using vertical wells, the probability to intercept natural fractures is very low as soon as fracture spacing exceeding 10ft which is very common in oil and gas reservoirs.(from Lorenz 1992)

HFTS-1: one swallow does not make a spring

A consortium of companies, government agencies and universities joined their efforts to take and interpret 600ft of core in a hydraulically fractured Wolfcamp reservoir in the Permian Basin, USA. Despite the detailed descriptions of the natural fracture system in the same basin (Lorenz et al. 2002), HFTS-1 publications show surprise at the abundance of natural fractures observed in the unique core taken in a slanted well. That abundance of natural fractures appears to have played a major role in the number of hydraulic fractures that were also observed on the same core. It is this critical observation that makes the natural fractures so important for the development of unconventional reservoirs.

Shrivastava, et al. (2018) attempted to model the interaction between natural and hydraulic fractures to try to reproduce the HFTS-1 observations in terms of generating the resulting hydraulic fractures. They used as input in the models a statistical distribution of the natural fractures which reproduced the observed fracture orientations seen in the HFTS-1 core (Figure 3). Unfortunately, the model was not able to reproduce the observed hydraulic fractures which were about ten by frac stage while the model predicted only two. The authors attributed this lack of predictions to the use of a natural fracture model that was missing the small fractures that had a length less than 2m (Figure 4) and the possible role of bedding planes which act as weak interfaces and can greatly influence the propagation of hydraulic fractures. Figure 4 shows that the small fractures less than 2m in Shrivastava, et al. (2018) model represents 25,000 fractures, yet the authors attribute the lack of 80% of the hydraulic fractures missing in their model to not having enough small fractures. If 25,000 small fractures are not enough for modeling such a small volume of reservoir, one may ask how many natural fractures are needed to capture the physics of hydraulic fracturing along many 10,000 ft wells in a pad or a cube?

This is similar to a question Henry Darcy asked himself in the 19th century when trying to model flow in porous media. Given the complexity of the pore space, would it practical for an engineer to capture that complexity or simply find an empirical relationship that reduces that complexity in a Representative Elementary Volume (REV) to one single parameter Darcy named permeability?

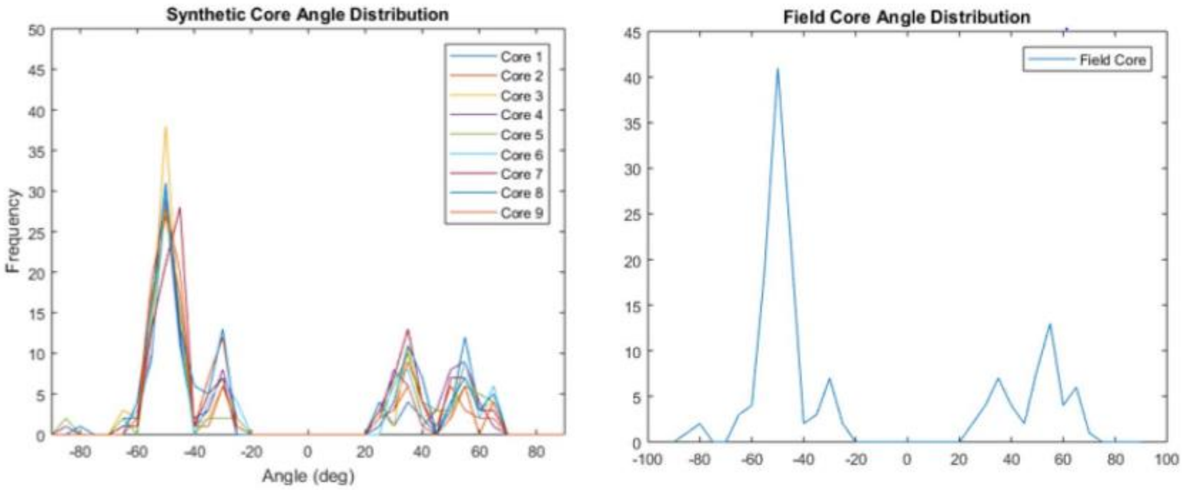
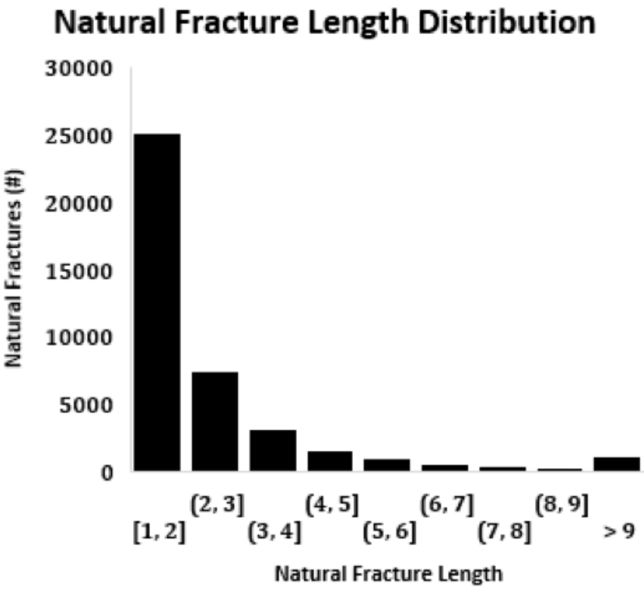


Figure 3: (left) orientation of natural fractures observed in synthetic cores extracted from a natural fracture model. (right) orientation of the natural fractures observed in the HFTS-1 slanted core. (Modified from Shrivastava et al. 2018)

Figure 4: Natural fractures length distribution used for building a statistics based natural fracture model used to simulate the hydraulic fractures in the HFTS-1 slanted core. (Modified from Shrivastava et al. 2018)



Today the oil industry uses permeability in Darcy's equations because of its empirical validity. One century after the development of the empirical Darcy equation, Whitaker (1986) proved its theoretical validity by applying homogenization theories to the Navier-Stokes equation. In other words, engineers have always raised to a scale large enough to capture the physics with the limited and measurable data they had at hand. The same process was used when developing the Continuous Fracture Modeling (CFM) approach to address the problem of poor statistics in naturally fractured reservoirs.

Addressing poor statistics by combining structural geology and artificial intelligence

In 1993, a New Mexico operator that had multiple Bone Springs fields in the Delaware basin commissioned a reservoir simulation study to address the declining production and to find infill locations. Despite 13 years of production and 36 wells drilled in the considered small field not a single well or log had shown the presence of natural fractures. Just like Abraham Wald with the WWII planes, the poorly-sampled statistics showing no natural fractures in the 36 wells, did not drive the natural fracture modeling effort that was inspired from structural geology concepts. The resulting natural fracture model not only matched all the well performances but also allowed the drilling of the best well that encountered a large number of natural fractures that were observed in the only core taken in the field to prove the existence of the natural fractures. The case study is described in detail in Ouenes et al. (1994) and lead to the development of the Continous Fracture Modeling (CFM) approach described in Ouenes et al. (1995). Two decades later, the CFM approach provides the necessary input needed to model the fracture complexity resulting from the interaction between hydraulic and natural fractures.

What matters in hydraulic fracturing and how to capture it with predictive models?

After many years of "natural fracture denial", the oil industry is recognizing the importance of natural fractures in hydraulic fracturing and the resulting well performances. The contribution of the HFTS-1 to this understanding is significant even though the 600ft core does not necessarily explain all the key factors affecting hydraulic fracturing. Another major aspect missing in HFTS-1 is the lack of predictive models derived prior to the well operations and that can be validated by the measured data. To the best of our knowledge no natural fracture model was derived before the field operations and its results confronted to the observed reality. Maity (2018) used the HFTS-1 microseismic results after the fact to better understand stress variations and find possible correlations with hydraulic fracturing parameters. Three years before Maity (2018), in the same Wolfcamp formation and also in Reagan county, Ouenes et al. (2015) prefered to understand the role of the natural fractures and their interaction with hydraulic fractures by predicting the resulting microseismicity.

Hydraulic fracturing's main goal is to create fracture complexity which greatly depends on the presence of the natural fractures and their interaction with hydraulic fractures. Given the challenges of finding a realistic distribution of natural fractures, one have to use all possible means to estimate the distribution of natural fractures including seismic data. Figure 5 shows how a simple coherency cube is used to derive an Equivalent Fracture Model (EFM) which is derived from the CFM approach where each cell has a fracture density and a dominant fracture orientation. When studying a given problem, one can chose the threshold needed to filter a continuous fracture model to capture the physics of the stated problem.

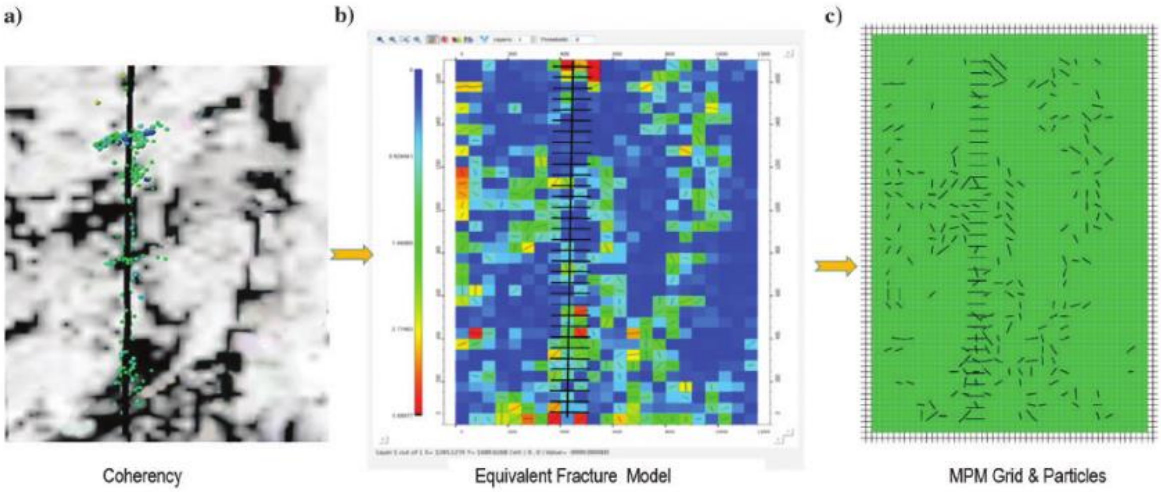


Figure 5: (a) coherency derived from seismic and resulting (b) Equivalent Fracture Model used as input in the (c) MPM derived geomechanical simulation (modified from Ouenes et al. 2015)

Using the continuous coherency map (Figure 5a), Ouenes et al. (2015) used a cut-off that lead to a distribution of the key natural fractures (Figure 5b,c) that could influence the hydraulic fracturing process. This natural fracture distribution when used in full continuum mechanics equations solved with the Material Point Point (MPM) as shown in Aimene and Ouenes (2015), leads to multiple results including the differential stress (Figure 6b). The role of natural fractures starts by perturbing the regional stress field and creates areas of low differential stress where recorded high microseismcity (Figure 6a) confirms the suspected role of the natural fractures to create fracture complexity when low stress anisotropic conditions are created.

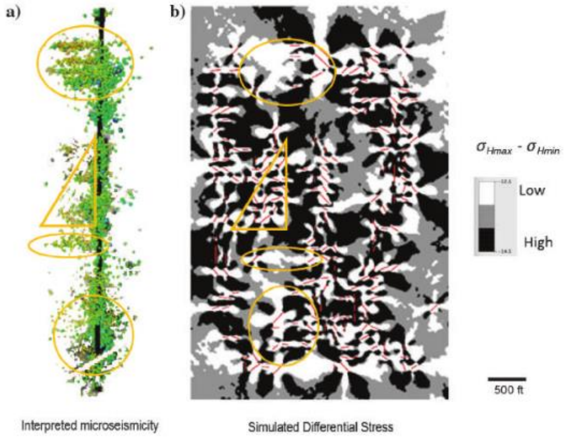


Figure 6: (a) microseismic response along the horizontal well and its correlation to (b) low differential stress zones predicted from MPM based geomechanical simulation. (modified from Ouenes et al. 2015)

The validation shown in Figure 6 indicates that the limited natural fractures shown in Figure 5c are enough to quantitatively describe very complex physics and provide a better understanding of the role of natural fractures in hydraulic fracturing, and such a process does not necessarily require an additional 25,000 small fractures. This conclusion is confirmed when simulating the MPM geomechanical modeling of the actual hydraulic fracturing and the resulting interaction between the hydraulic and natural fractures. Figure 7 shows the predicted strain and its high correlation with multiple key features of the complex microseismicity recorded during hydraulic fracturing. The same exercise could have been applied to HFTS-1 prior to its drilling and hydraulic fracturing to better understand its behavior. Unfortunately, Maity (2018) analysis of the HFTS-1 microseismic data at few stages was limited to superposing it to seismic attributes highlighting the role of the natural fractures as shown in Figure 8.

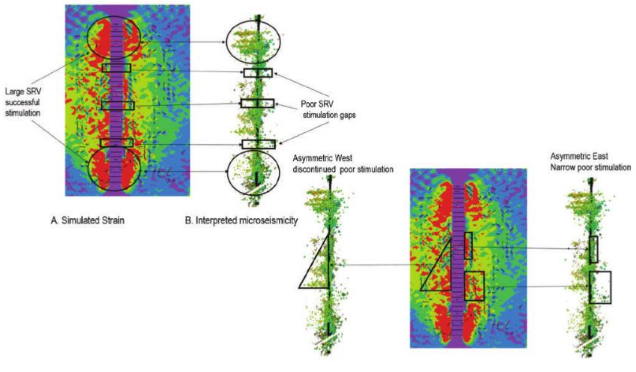


Figure 7: Comparison between the predicted strain derived from the MPM geomechanical simulation and the recorded microseismcity at all the stages (modified from Ouenes et al. 2015)

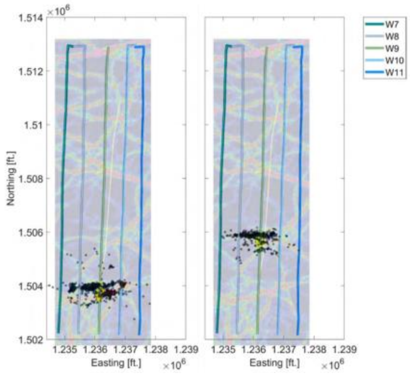


Figure 8: HFTS-1 recorded microseismcity at two stages overlain over a seismic attribute that could indicate the presence of natural fractures (modified from Maity, 2018)

In both cases described in this section from Reagan county, we see that seismic data provided the necessary input to quantitatively in the case of Ouenes et al. (2015) example, and qualitatively in the case of HFTS-1 described by Maity (2018), capture the effects of natural fractures on the stimulation as shown by the microseismic data. The question is what alternatives do operators have in case they lack seismic data and a detailed description of natural fractures from core or image logs? The answer can be found in the use of surface drilling data which could be used to estimate a natural fracture index, pore pressure, stresses and geomechanical logs at any past, present and future wells. The science behind this approach is described in Ouenes et al. (2019) and provides the necessary means to quantify the role of natural fractures in any circumstance.

Conclusions

Given the recognized importance of the natural fractures in the development of unconventional reservoirs, the sparse statistics created by the lack of cores and image logs requires practical engineering approaches and solutions. Among these solutions is the use of a continuous fracture model that uses a representative volume to describe the fracture density that can be estimated from seismic and surface drilling data. This approach leads to a quantitative use of these natural fractures and their interaction with hydraulic fracture using a robust geomechanical simulation able to predict microseismicty thus validating both the used natural fracture model and the geomechanical modelling approach.

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