Integrated Fracture Modeling Using Seismic Data

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Abstract
Given the importance of fractured reservoirs in the world, and the ever-increasing availability of 3D seismic data, this paper reviews existing fracture modeling approaches that use 3D seismic data. Two major approaches appear to provide efficient ways to use directly and effectively 3D seismic data. The first approach uses mostly post-stack data in an integrated computational framework where 3D seismic attributes are used along with other geologic and geomechanical information to provide reliable 3D fracture models. The second approach relies on the use of pre-stack seismic data along with other geologic and production information to provide an accurate description of the fracture density and orientation. Although these technologies are well proven and have been tested in many basins, they remain underutilized by most oil and gas companies, with the exception of a few companies that have been using them extensively to drill very successful wells.

Introduction
Fractured reservoirs are becoming a major issue throughout the world both for old and new fields. The old fields are reaching maturity and something must be done to extend their life. The most common solution is to use secondary or tertiary recovery processes which are creating unpleasant surprises as they exaggerate the effects of fractures. Additionally, many newly discovered oil and gas fields happen to be fractured and their development constitute a real challenge in these difficult times where the E&P industry must deliver high returns to its shareholders. Fortunately, most of these companies have acquired 3D seismic data which provides a wealth of information that can assist in meeting the challenges.

The use of 3D seismic data in fractured reservoir modeling remains a major priority for most oil and gas companies operating throughout the world. The major problem facing these companies is to find the right technology or tool to fully utilize their data especially the recently acquired 3D surveys.

When facing the problem of modeling a fractured reservoir, oil and gas companies have three available approaches. The first one is the geomechanical approach where an attempt is made to reconstruct the tectonic history of the fractured reservoir. Unfortunately, all the existing tools in this approach employ overly simplistic models where the complex geology of the reservoir is ignored and homogenous and isotropic rock properties are assumed in the calculations. Furthermore, the end result of this approach is a strain map, which is typically very similar to a simple curvature map easily derived from the current structural surfaces. Another major deficiency in this approach is the assumption that present day open fractures are only related to tectonic events as if diagenesis and mineralization did not exist and had no effect on fractures after they were formed. In addition to the inability of this approach to account for the complex and heterogeneous geology of all fractured...
reservoirs, there is no room to incorporate any 3D seismic attribute in the geomechanical modeling process.

The second approach commonly used to model fractured reservoirs is the Discrete Fracture Network (DFN) where the reservoir volume is filled with fractures represented by planes or disks. For many years the DFN models lacked geologic realism since the fractures were randomly distributed in the reservoir, ignoring the fact that fracture density at any point is affected by the thickness of the reservoir at that point, its lithology and porosity, its proximity to faults and numerous other geologic drivers. Since the introduction of DFN models there was a need for constraining the realizations to some geologic input, and attempts have been made to control the fracture generation with some indicator. However, these attempts used a single geologic driver, excluding other factors, and most importantly did not account for the complex interplay of the drivers. Ouenes and Hartley introduced the concept of a conditioned DFN where a significant effort is spent in integrating all the geologic drivers in a continuous fracture model which is then used to constrain the DFN models. A recent field example illustrating this approach is given by Zellou et al.

Finally, the third approach uses a continuous framework where many geologic drivers could be incorporated in creating an integrated fracture model. These continuous fracture models stem from the simple observation that fracture intensity depends on many geologic drivers, the most commonly known being, structural setting, proximity to a fault, lithology, porosity and thickness. Because all these drivers and their complex interaction must be accounted for during the modeling process, Ouenes et al. uses a regular 3D grid model similar to the one used in geologic modeling or in seismic cubes along with a collection of artificial intelligence tools, to create truly integrated fractured reservoir models. The approach described in detail in Ouenes was successfully used on various fields and basins and one of its most striking advantages is its ability to integrate seismic data in the modeling process.

In parallel to these efforts, geophysicists have been trying to use directly pre-stack seismic data to detect fractures. The early observations made by Crampin on azimuthal anisotropies have been adopted with enthusiasm and fully developed to a point today where it is now possible to simply image the fractures.

This paper reviews the two major readily available approaches that use seismic data in fracture modeling. Emphasis is given to the applications of these approaches to actual fields.

**Fracture Modeling Using Seismic Data**

From its debut, the continuous fracture modeling approach provided a unique opportunity to use seismic data. The methodology assumes the existence of a complex relationship between a large number of geologic drivers plus seismic indicators derived from any pre-stack or post-stack seismic analysis and a given fracture intensity that could be defined at the wells from image or conventional logs, cores, or simply production data. As the geologic drivers and seismic indicators are available as 3D volumes in the entire reservoir and the fracture density is only known at the well locations, a neural network is
used to find the existing underlying relationship between the input (geologic drivers and seismic indicators) and the output (fracture intensity). Once this relationship is found and tested, then a 3D volume of the desired fracture intensity can be derived. The neural network is used as an integration tool able to find the complex underlying relationship. Other Artificial Intelligence tools could be used instead of the neural network as long as no a priori assumptions are required about the underlying relationship between drivers and fracture intensity.

Using Conventional Seismic Attributes
Numerous large integrated reservoir studies\textsuperscript{8-11} used this continuous fracture modeling methodology to integrate seismic data in the fracture modeling process. Zellou\textsuperscript{8} \textit{et al.} used the seismic amplitude along with other geologic and geomechanical indicators to improve the fracture intensity models. In this case, the seismic attribute was not derived from a seismic analysis process such as inversion, spectral imaging, or simply coherency.

Gauthier\textsuperscript{9} \textit{et al.} used the seismic data in many ways. First, the faults were mapped with the seismic data and a pseudo-strain map was derived from the detailed fault interpretation. Second, the amplitude and coherency were used as drivers in the integrated fracture modeling workflow.

An improved way that takes full advantage of the 3D seismic data and the available logs is to use a pre-stack or post-stack seismic analysis process. The most widely used seismic analysis tool is inversion, where the objective is to derive an impedance volume which in turn could be used to improve the geologic modeling as well as to directly benefit the fracture modeling. Ouenes and Hartley\textsuperscript{2} used this approach to add an impedance volume to the fracture modeling process. The derived fracture model that integrates seismic data with many other geologic and geomechanical drivers was used to condition a DFN model. Zellou\textsuperscript{3} \textit{et al.} also used a seismic impedance cube along with other drivers to derive a fracture model which was used to estimate the matrix block size required for a steamflood simulation.

Since pre-stack or post-stack seismic analysis could lead to many attributes, Gomes\textsuperscript{10} \textit{et al.} used a multitude of seismic attributes in their fracture modeling. In addition to acoustic impedance they added reflection strength, azimuth, amplitude and other seismic attributes. The use of a multitude of seismic attributes was also found in Laribi\textsuperscript{11} \textit{et al.} where the seismic inversion was fully utilized to derive a density and velocity cube in addition to an impedance cube. A coherency cube was added to the three seismic attributes derived from the inversion to enhance the predictive capability of the fracture models. These models were tested with the drilling of a horizontal well. The drilling results (Fig. 1) showing the fracture porosity model versus the recorded image log, indicate clearly that the addition of seismic data in the fracture modeling process allows the prediction of the presence of fractures before drilling.

Other drilling results have shown clearly that the extensive use of seismic attributes derived from pre-stack or post-stack seismic analysis is a significant factor in creating accurate fracture models. After a careful analysis of almost a decade of using seismic attributes in integrated fracture modeling, some major observations can be made regarding the use of
seismic attributes in fracture modeling.

In the early use of seismic data, as illustrated in Zellou et al., simple seismic attributes such as amplitude were added to the other geologic drivers. It was clear that this new driver or indicator improved the fracture modeling process, but it appeared that more benefits could be derived from the use of seismic. The integrated fracture modeling approach tries to shift the focus from the fractures to the drivers. Hence fracture modeling becomes a relatively simple problem where all the possible drivers must be mapped in the reservoir volume. Some of these drivers are thickness, lithology, porosity, distance to faults, et cetera. By looking carefully at all these drivers, one realizes that most of these drivers could be very accurately derived from seismic data. For example, a high resolution inversion could lead to an impedance, density and velocity cube. These seismic attributes could be used along with the well data to derive very accurate lithology and porosity models which are key geologic drivers in any fractured reservoir. For structural information, different coherency techniques allow an accurate identification of the faults. Hence, the distance to the faults, which is a major driver in most fractured reservoirs, becomes available. Other new powerful seismic analysis tools allow definition of additional geologic drivers.

New Drivers Using Spectral Imaging

In addition to high resolution inversion and coherency techniques, spectral imaging is providing a powerful tool to derive, without using geostatistics, key geologic drivers from seismic and log data. Spectral imaging is a workflow that utilizes log and seismic data to image key reservoir properties. The workflow consists of many steps, with the final being the use of spectral decomposition.

Spectral decomposition was introduced as a tool for imaging and mapping temporal bed thickness and geological discontinuities over large 3-D seismic surveys. This technique has been used to delineate facies and depositional environments such as channel sands and incised valley-fill sands. Spectral decomposition typically employs the discrete Fourier transform (DFT) to generate mono-frequency images from the broadband seismic data. However, the type and length of the window used in the DFT produce limitations in the resolution of the output. The wavelet transform allows a seismic signal to be examined in both the time and frequency domains simultaneously. It has become a popular tool for the analysis of non-stationary signals and has replaced the conventional Fourier transform in many practical applications including in spectral decomposition applications.

When using the wavelet instead of the Fourier transform and adding pre-processing steps that include the use of log data prior to any spectral decomposition, and finally taking advantage of key concepts related to the attenuation of seismic signals and their implication on reservoir properties, one can produce many seismic attributes that reveal intimate details of the reservoirs. Among these attributes one can find the reservoir thickness, lithology, porosity, sub-seismic faults, hydrocarbon content and many other reservoir properties that are directly related to fracturing. Since these attributes are available in the entire reservoir with a very high vertical resolution, one does not need to use interpolation techniques or geostatistics to derive a 3D volume of the fracture drivers. Many recent field examples have shown that the combination of spectral imaging and high resolution inversion provides all the drivers needed for any fracture modeling problem with
an accuracy never previously attained. In other words, the use of post-stack seismic data alone, combined with efficient seismic analysis tools such as high resolution inversion and spectral imaging could provide all the drivers needed for the fracture modeling. If pre-stack data is available, one can use pre-stack seismic analysis tools to derive more attributes directly related to rock mechanical properties that further enhance the fracture modeling process.

Despite the ability of these seismic techniques to image accurately the reservoir boundaries, geology and fracture drivers, one has to remember that none of these drivers is a direct indicator of fractures by itself. Fracture modeling, using all the drivers and some fracture intensity defined at the wells, is still required. Because the presence of fractures in the reservoir creates wave scattering, a different approach could be used to directly image the fractures using pre-stack seismic data.

**Fracture Imaging Using Pre Stack Seismic Data**

When shooting seismic data, each seismic trace records reflected waves traveling from the shot to a receiver. The midpoint is the point that is equidistant from the shot and receiver. Because, there are many receivers on the grid, there are midpoints at different distances from the shot, with different incidence angles (Fig. 2). When processing the seismic data, each bin (gather) contains the midpoints of many shot-receivers pairs that have different azimuths and incidence angles (Fig. 3). When examining a gather where the unstacked traces are plotted with an increasing offset distance, one can observe amplitude variations as a function of offset. This is the key observation used in azimuthal analysis. When considering the pre-stack seismic data, one can show theoretically and computationally that for simple fractured reservoirs as shown in Fig. 4, the amplitude when plotted versus the incidence angle shows a separation for different azimuths (Fig. 5). This is the observation used in AVO analysis for fracture detection.

Since the early ideas proposed by Crampin\textsuperscript{12} et al. about the use of pre-stack seismic data to detect fractures, many teams\textsuperscript{17-24} have exerted significant efforts to find practical ways to accomplish this. Unfortunately, this area turned out to be a very challenging scientific domain where the solutions seem to be very complex. As in any other scientific discipline, when a problem is very complex, we tend to make simplifying assumptions to reach a first order solution. Many simplifying assumptions were made in this area and as a result many dry holes were drilled. These dry holes were drilled in the wrong locations because the geologic realities of fractured reservoirs were not incorporated in the modeling process and oversimplifying assumptions were made.

Most of the work done in azimuthal analysis geared towards fracture detection has been plagued with many unrealistic assumptions. The most common being:

1) The assumption that the fractures are vertical
2) The fractures are 100% filled with only one fluid
3) The background reservoir is homogeneous
4) The reservoir structure is almost flat

As these assumptions are not realistic for most fractured reservoirs, approaches utilizing
these assumptions will tend to produce inaccurate fracture density predictions. These assumptions are made in order to limit the sources of anisotropy in the data; the problem is how to distinguish between the anisotropy created by the fractures themselves and the “undesirable” anisotropy created by the gas content, reservoir heterogeneity, and reservoir structure. Because of the inability to distinguish between these undesirable anisotropies and the one of interest due to the fractures, many workers have simply assumed that the anisotropy due to gas, heterogeneities and structure does not exist or can be ignored.

There are three simplifying assumptions which have significant adverse effects upon fracture modeling. The first one deals with the issue of vertical fractures. For basic mechanical reasons, most fractured reservoirs tend to have shear fractures with a non-vertical dip angle; it is very rare to have vertical fractures. By assuming vertical fractures, this unrealistic theoretical requirement creates a practical limitation. The application of such theory calls for seismic surveys where large offsets are available in the data. In many seismic surveys this is not available.

The second assumption widely used is the homogeneity of the reservoir surrounding the fractures. Despite years of efforts to model reservoir heterogeneities using all possible means, the simplistic assumptions of a homogeneous reservoir is still being used. As most of the fractured reservoirs occur in complex heterogeneous systems where facies, porosity, permeability and every other reservoir property changes vertically and areally, using this assumption in azimuthal analysis could lead to unexpected surprises. A good illustration of such a surprise can be found in Gray and Todorovic-Marinic\textsuperscript{25} where the authors noticed that “…the AVAZ results, which are supposed to indicate the presence of fractures, are actually indicating the presence of sands in this reservoir”. In other words, the lack of ability to account for reservoir heterogeneity in the azimuthal analysis results in geologic features (presence of sand in this case) other than the fractures being imaged in the azimuthal analysis. The importance of heterogeneities in azimuthal analysis and ways to account for them are addressed in details in Shen\textsuperscript{22} et al.

The third assumption used in most of the azimuthal analysis for fracture detection is that the fractures are 100\% filled with one single fluid. In other words, the fractures are either filled with a liquid or gas. Unfortunately, most fractured reservoirs have both fluids present in the fractures. Because of the large density difference between liquid and gas, the anisotropy ellipse could be dramatically affected by the presence of gas leading to inaccurate fracture predictions. For example, Lynn\textsuperscript{18} et al. using this assumption of 100\% filled single fluid fractures concludes that fracture strike is aligned along the maximum gradient direction. Both Sayers and Rickett\textsuperscript{26} and Shen\textsuperscript{24} et al. have shown that this conclusion is not true because the change in fluid content (and corresponding bulk modulus values) from gas to water can lead to large azimuthal variations in AVO responses. The effect of fluid content may be more important than that of elastic properties of reservoir rocks in some cases.

Many of the simplifying assumptions made in the area of fracture detection using azimuthal analysis are not currently needed as extensive work\textsuperscript{20-31} have improved seismic anisotropy analysis techniques, and fracture “imaging” is possible today without using the common simplifying assumptions.
The approach routinely used today relies on four major steps and a collection of seismic modeling technologies. The first step is rock physics modeling, where the fluid content is taken into account instead of assuming a 100% filled single fluid fracture (Fig. 6). This critical step requires the use of P- and S-wave velocities, rock density and related geologic information. In general, P-wave velocity and density are available from log data. If the S-wave velocity is not available, the rock physics model is used to estimate it from available porosity and shale content. Once the rock physics model of the fractured reservoir is built, the 3-D time domain, staggered finite difference method is applied to modeling wave propagation in fractured reservoirs and to obtain accurate azimuthal AVO responses. The derived models provide an indication on how fluid contents and fracture density influence the azimuthal seismic responses, and the relationships between the seismic anisotropy and fracture orientation.

The second step consists of modeling the reservoir heterogeneity. A collection of seismic modeling tools make this task easy and gives an accurate description of the reservoir. Since pre-stack seismic data is available, P- and S-wave impedances are obtained by using elastic impedance inversion (Fig. 7). P- and S-wave impedances indicate the lithology differences between the fractured reservoir and overlaid rocks and lateral variations of rock properties within the reservoir. In addition to elastic inversion, spectral imaging and high resolution inversion provide a very accurate modeling of the reservoir heterogeneity which is taken into account in the interpretation of fracture orientation and density in the next step.

Once the reservoir heterogeneity is known, azimuthal analysis can be initiated by using appropriate seismic attributes to identify fracture orientation (Fig. 7). To characterize fracture density, the use of amplitude itself for such analysis could be misleading and other seismic attributes related to wave attenuation are more efficient.

The final step consists of integrating all the different models of fracture density and fluid saturation with production data to plan for future drilling locations or to create fracture porosity and permeability models. These inputs for reservoir simulation can be derived in each bin directly from the azimuthal analysis or upscaled to a larger grid size. A practical example of the end product of this process is shown in Figs. 8 and 9. The azimuthal analysis leads to a fracture density model that provides in each bin the effective fracture density as well as the dominant fracture orientation in that bin (Fig. 8). Because rock physics modeling is used, the saturation of hydrocarbons in the open fractures becomes available (Fig. 9) and drilling of new wells becomes much simpler as the two major reservoir parameters, fracture density and hydrocarbon accumulation, are now determined. In the example shown in Figs. 8 and 9, the two wells at the bottom of the map were drilled prior to the study. The left well was a dry hole and the right well became a good producer after a major frac job that connected the well to a fracture swarm filled with hydrocarbons north of the well. Following the study, a third well was recommended in the north part of the study area in the highest fractured zone located next to a major hydrocarbon accumulation. The well was drilled and is the best producer of the area.

When simply looking for drilling locations, fracture imaging techniques such as the ones described above are sufficient for the initial stages of field development. When planning,
long term field development strategies one needs to create reservoir models which requires the fracture permeability and porosity independently of the nature of the fracture reservoir (which could be single, double or triple porosity). After imaging many fractured reservoirs and testing the validity of the models with actual drilling, one could now focus on the problem of estimating fracture permeability.

When considering a recent field example shown in Fig. 10 which shows the fracture density and orientation in a 20m bin, one can see the various changes in fracture density and orientation from one location to another. These changes are not a mere result of some seismic analysis algorithm but could be explained and supported with geologic data and actual drilling results. When trying to simulate the fluid flow in such a complex system, one can see immediately that the commonly used rectangular grid and diagonal permeability system (Kx, Ky, Kz) will pose a serious problem as the fracture orientations vary significantly even within a small area. To account for this geologic reality, two major efforts are needed in the near term. The first one is the general use of a full tensor permeability with off-diagonal terms to be able to account for various flow directions caused by varying fracture orientations. Although the ability to compute full tensor fracture permeability from fracture imaging or modeling exist for many years, its use in commercial reservoir simulators remains very limited. This full tensor fracture permeability effort poses many challenges including those related to the computation time, and is unlikely to have a quick solution. The second effort is the general use of unstructured grids to simulate fractured reservoirs. This solution already exists, is available in commercial simulators, and has been tested on many fractured reservoirs where the fracture permeability was derived from an integrated fracture modeling approach. A recent example of the use of unstructured grids in large integrated fractured reservoir studies is shown in Laribi et al. This could become the standard way of simulating fractured reservoirs in the near future.

Conclusions
After almost a decade of intensive work in the area of fracture characterization, it appears that the end of the tunnel is nearby and there is some light in sight. Extensive drilling and close collaboration with select E&P companies has demonstrated that fracture density and orientation can be predicted accurately before drilling. The mystery behind some major fractured reservoirs has been solved by simply integrating a large amount of available reservoir data into coherent fractured models.

The integration process became possible when an appropriate computational framework allowed to shift the focus from the fractures to what controls them - the drivers. These drivers, although known among geoscientists for many decades, have been rarely used in an integrated way. Artificial intelligence tools allowed the integration of all existing and possible geologic drivers, which ultimately lead to accurate fracture models described either with static or dynamic data.

After using simple mapping methods and geostatistics to create 3D models of the geologic drivers, the next step was to take advantage of the seismic data to derive accurate descriptions of these drivers in the reservoirs by combining the use of geostatistics and 3D post-stack seismic.
Finally, it became clear that the use of log data and seismic imaging techniques such as high resolution seismic inversion and spectral imaging could provide directly the geologic drivers needed for fracture modeling. This eliminates the need for geostatistics since the drivers are imaged directly by combining the log and seismic data.

When pre-stack seismic data is available one can find a more accurate description of the fracture density and fluid saturation in the fractures by using azimuthal analysis. However, the successful use of this technology requires some precautions. Making overly simplified assumptions may result in unrealistic fracture models. Since many geologic factors such as the presence of gas, reservoir heterogeneity, and reservoir structure can cause anisotropy, one has to be able to account for these effects before embarking in the use of azimuthal analysis for fracture detection. Assuming that there is no gas, the reservoir is homogeneous, and the structure is flat is not acceptable for most of the fractured reservoirs.

The successful use of azimuthal analysis requires the use of rock physics modeling to take into account the effects of various fluids present in the fractures. Once the fluid effects are understood, then the reservoir heterogeneity must be resolved by using various imaging techniques such as elastic inversion, spectral imaging, or high resolution inversion.

After taking into account the fluid effects and the reservoir heterogeneity, one can use azimuthal analysis on a seismic attribute other than amplitude to estimate the effective fracture density and orientation in each bin.

The end products of the azimuthal analysis is an accurate description of the fracture density as well as their fluid content, which then can be used to drill successful wells or to derive a fracture porosity and permeability model.

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References:

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Fig. 1: (Courtesy of SPE 84455) Comparison between actual FMI recorded after drilling and the fracture porosity model derived before drilling. Notice the ability of the model to predict a 100m zone free of fractures (red arrow) followed by another very fractured zone (cyan arrow) and the vanishing of the fractures at the end of the wellpath.

Fig. 2: Seismic Survey made of many pairs of shot-receivers. Each receiver records a signal that have a different incidence angle.

Fig. 3: When processing seismic data, each bin (gather) contains the mid-points of many shot-receivers pairs that have different azimuths and incidence angles.
Fig. 4: Simple conceptual fractured reservoir commonly used in azimuthal analysis.

Fig. 5: Separation for different azimuths.

Fig. 6: Rocks physics modeling is used to take into account the effect of fluid saturation.

Fig. 7: Azimuthal analysis applied on the inverted elastic impedances in five azimuths as one of the means to account for reservoir heterogeneity.
Fig. 8: Effective fracture density and orientation shown in each bin

Fig. 9: Hydrocarbon saturation in the open fractures.

Fig. 10: Fracture imaging reveals the complexity of the fracture network