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Am I Really Predicting Natural Fractures in the Tight Nordegg Gas Sandstone of West Central Alberta? Part I: Theory and Statistics

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Summary

Exploration and development of the Nordegg in West Central Alberta is challenging because this prolific zone is deep, structured, and has low permeability. The reservoir is quite thick and is charged with gas. We know from core, samples, well log, and drilling data that the Nordegg zone is fractured to some degree. We expect this fracturing will affect the behavior of the Nordegg to our operations in many ways, from the drilling, to the way that the reservoir behaves under fracture stimulation, and even to the production rates we may achieve from the zone. The fracture density and the production capability of wells drilled into the Nordegg vary materially. In order to address the questions surrounding the effect of fractures on our operations, we must first demonstrate that we can accurately predict the orientation and density of the fracture systems within our area of interest. 3-D surface seismic techniques such as Azimuthal AVO (AVAz), Azimuthal Velocity Analysis (VVAz), Curvature, and Coherence techniques have all been used to predict fractures in a qualitative way in the past. Our approach to the fracture prediction problem will contrast these earlier qualitative attempts, and attempt to cast the problem within the framework of an objective, scientific experiment. Very little information exists in the literature regarding the true accuracy and validity of fracture prediction from surface seismic, so the importance of this endeavor and the need for care in its undertaking is magnified. Our goal is a quantitative analysis of fracture prediction techniques for the Nordegg using objective and scientific validation data. Our validating data includes fracture density data measured from Fullbore Micro Imager Log (FMI) recorded in two horizontal wells as well as microseismic event data recorded over one of the two wells. In part one of this effort, we will describe the experimental set-up and make observations regarding the statistical nature of the FMI data and our seismic attributes. The most crucial result illustrated in part one is that the FMI data clearly illustrates the fractures are almost uniformly vertical and aligned. This satisfies key theoretic requirements of AVAz and VVAz.

In part two of this work, we will analyze the correlations that exist between FMI fracture density, microseismic events, and our seismic attributes.

Introduction: The Nordegg Formation

The Nordegg Formation in the Columbia-Harlech area is typically a lower chert/carbonate rock type overlain by a upper porous quartz-arenite sandstone reservoir which is unconformably overlain by the Poker Chip shale. Porosity within the lower Nordegg is bio-moldic in origin and is developed from the remnant bivalves shells, pelecypods and pelloids deposited in the platform environment. The upper Nordegg contains a porous phosphatic sublithic arenite sandstone facies, which is interpreted as having been deposited in a shallow marine ramp setting. The intergranular porosity, within these meter scale phosphatic sublithic arenite sandstone interbeds, was preserved due to presence of silica and calcite cements during burial and compaction. Post burial migration of fluids partially to extensively removed the calcite cement and unstable grains (e.g., phosphate pellets) from the sandstone, establishing the reservoir quality intergranular porosity and enhanced secondary porosity.

Reservoir parameters of the Nordegg interval within the Columbia- Harlech area averages about 12m of net pay (> 6% SS porosity) with an average log porosity of 7% and 14% water saturation. Core permeability ranges from .01-.1 md. The majority of the deliverability and enhanced permeability within the Nordegg is created from the areas' complex system of faults and fractures associated with strike-slip style faulting.

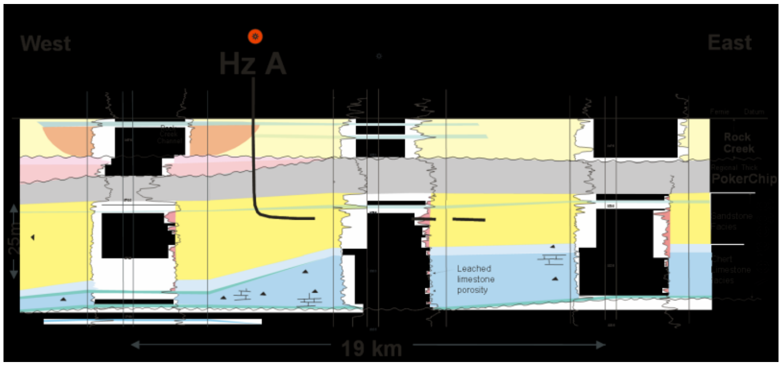


Figure 1: Stratigraphic cross section of the Nordegg in local wells. Logs displays include gamma ray, and density porosity curves. The horizontal Well A is depicted as if it intersects a nearby vertical well.

There is extensive 3D surface seismic coverage in the area which enabled the identification and mapping of the major structural features of the Nordegg. Three wells (Well A, B, and C) were drilled into several of the interpreted structural archetypes present in the area. Figure 2 illustrates these structural archetypes and the relative positions of the wells.

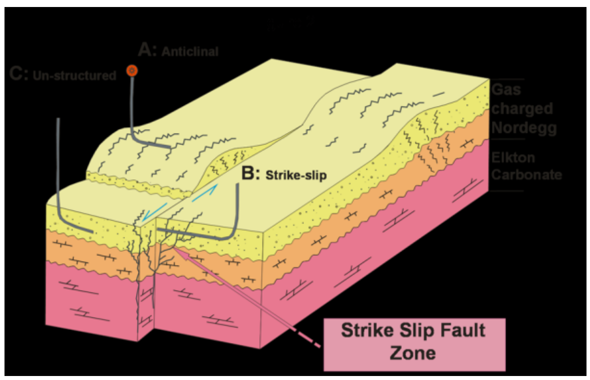


Figure 2: Structural schematic illustrating the relative position and setting of horizontal wells A, B, and C.

Well A was drilled along the strike of an anticlinal feature, Well B was drilled into a major strike slip feature, while Well C was drilled in a relatively unstructured setting. FMI logging was performed for Wells A and B. A microseismic experiment was also performed for part of the completion of Well A.

Subsequent to the drilling of these wells, processing was performed on the 3D seismic data in an attempt to produce attributes that characterize, explain, and predict the fracture density at the wells and throughout the rest of the 3D survey. Most of the rare, past, attempts at objectively testing fracture prediction such as Gray's (2003) paper has used production data to validate the attributes. This approach was important and has validity, despite the fact that production is often affected by more variables than fracture density. The FMI data that we use in this work should be a superior data element in regards to testing fracture prediction, as it's expected relationship to the seismic attributes is more direct. A comparison of the fracture predictor (AVAz, VVAz, Curvature, Coherence) against direct FMI fracture density measurements will provide a very clear, controlled, scientific basis for analysis. The use of microseismic event moments as a second, although less direct, element of validating data is also important. These validating data should enable a more complete and controlled scientific experiment than has been possible in the past, where such data has been difficult to acquire.

Theory

There are five theoretical concepts important to this experiment: AVAz, VVAz, Curvature, FMI log data, and Microseismic. The nature, meaning, and physical requirements of these concepts must be met in order for us to construct our test of fracture prediction in a scientifically meaningful manner.

AVAz describes the change in AVO as azimuth varies, while VVAz describes the change in velocity as azimuth varies. Both techniques can provide a direct estimation of relative fracture density and orientation if and only if the fractures meet stringent physical criteria. The crucial physical criteria for the theory behind AVAz and VVAz to hold true is that: the fractures are nearly vertical, and that they are aligned. AVAz and VVAz are also bound by resolution limits, with VVAz being much lower in resolution than AVAz. The azimuthal AVO equation of Ruger (1997) is also more difficult to solve as it is more complex than the Gidlow (1992) AVO equation. Moreover, the Ruger equation must also be solved on data sorted by azimuth, which is typically either less well resolved in a common offset vector characterized product, or less wells sampled in a azimuthally sectored and migrated product.

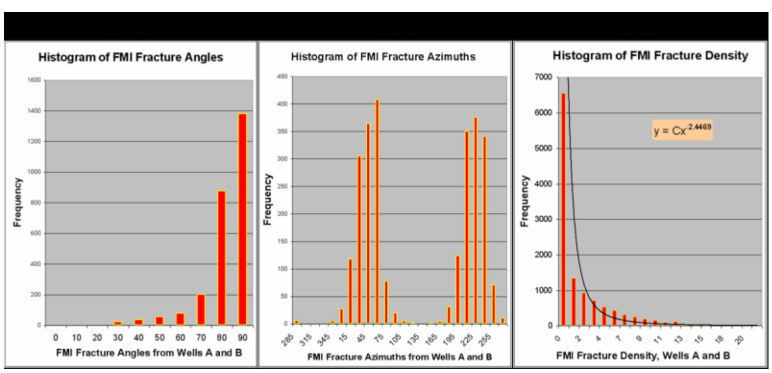
Curvature attributes essentially describe the structural shape of the seismic data. Anticlinal features, especially hinge zones, may be clearly defined by most positive curvature maps. Strain relationships with structural features are well understood, and it is this connection between structure, strain, and fractures that make Curvature a useful fracture indicator. Other causal variables of fractures such as lithology and in situ conditions such as depth and pore pressure, require that Curvature measures be calibrated carefully for each horizon and area. Similarity attributes such as semblance or coherence are also commonly used to predict stratigraphic or structural breaks- including faults- in seismic data, and require calibration to well control for the same reasons as the Curvature attributes.

The FMI log is a high resolution borehole image tool that can image fractures in the wellbore at the centimetre and millimetre scale by the contrast in resistivity that they create. The FMI tool provides its electrical image from micro-resistivity measurements. These images reveal information regarding structure, sedimentary features, and rock texture. Fracture orientation, aperture, porosity, and density can also be determined from this log and were used in this study.

Microseismic experiments are sometimes used to observe and map hydraulic fracture stimulations of reservoirs. The fracture stimulation growth may be mapped and calibrated from the seismic (event) moments as observed from surface and or subsurface monitoring during and after stimulation. Maxwell (2009) observed that the microseismic events result from an interaction between the stress induced upon the formation during stimulation, the pre-existing stress regime within the rock, and pre-existing fractures. As a result, there should be a correlation between microseismic events and pre-existing fractures. This implies that microseismic data could be used as another source of calibration and validation to surface seismic fracture predicting attributes.

FMI Data: are the theoretical requirements met?

The FMI data from Wells A and B represent combined log information from 1800 meters of Nordegg reservoir. Figures 3, 4, and 5 respectively describe some of the FMI fracture density data behaviour. This data is very clear in showing that the fractures are overwhelmingly vertical, have a common azimuth, and obey a power law distribution. The two sets of azimuths with respect to north shown in Figure 4 are actually the same azimuth, ie, they are 180 degrees apart. This data satisfies the theoretical requirements for AVAz and VVAz. Put another way, this data suggests that the fractures observed in the wells are of the correct nature to be estimated through these physical techniques.



Figures 3, 4, and 5, respectively, illustrate the statistical behaviour of the fractures observed by the FMI log. Figure 3 illustrates the angle from horizontal, Figure 4 illustrates the azimuth from North, while Figure 5 illustrates the density distribution.

Attribute Data: similar to the FMI data?

If surface seismic attributes are to estimate fracture density as measured by the FMI data, their distributions should have similar characteristics. Figures 6, 7, 8, 9, and 10 illustrate the distributions of our key surface seismic attributes. It can be observed that the AVAz, Curvature, and Coherence attributes seem to have similar characteristics to the FMI fracture density, although these attributes may also illustrate a second population in the data. This second population could be a flaw in the attribute, or it could be a result of the difference in the scale of observation of the surface seismic attributes and the FMI data. The VVAz attribute distribution appears more evenly distributed than the FMI and the other data. These differences will be explored further by involving larger sample statistics in the data. Of special interest is the observation that the AVAz estimated azimuth distribution of figure 7 is very similar to the FMI fracture azimuth distribution of figure 4, with dominant fracture strike azimuths of about 50 degrees east of north.

Figure 6

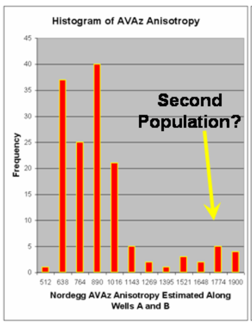


Figure 7

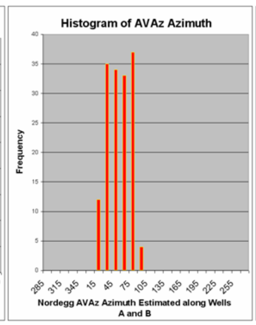


Figure 8

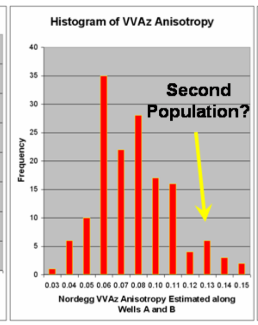


Figure 9

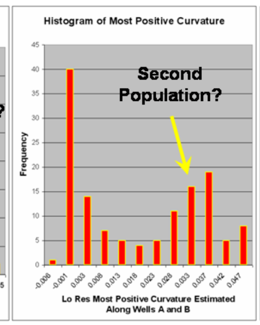
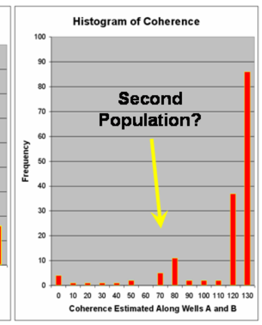


Figure 10



Figures 6, 7, 8, 9, and 10 respectively, illustrate the frequency distributions of the surface seismic fracture predicting attributes. Figure 6 represents AVAz crack density, Figure 7 illustrates AVAz Azimuth, Figure 8 illustrates VVAz anisotropy, Figure 9 illustrates low resolution most positive curvature, and Figure 10 illustrates coherence.

Conclusions

The FMI data illustrates conclusively in the logged wells that the fractures are vertical or nearly vertical, and that they have a single azimuthal alignment. Moroever, the fracture density obeys a power law distribution. Extending these observations, we expect that the AVAz and VVAz methods are physically valid over this dataset. We also illustrated that in some cases the surface seismic attributes had distributions with similar characteristics to the FMI fracture density data. This is of interest, and will be explored further, however having similar distributions does not prove that the variables are correlated with each other. That demonstration remains to be shown. Further conclusions and observations are reported in part two of this work, particluary focussing on how well these attributes predict the observed FMI fracture density.

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