Use of fault-scale seismic imaging to determine reservoir scale fracture size: Case study from Oregon Basin.

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Introduction

The South Oregon Basin field in the Big Horn Basin of Wyoming, currently operated by Marathon Oil Co., was discovered in 1912 (**Fig. 1).** This field has produced over 83 million bbl of oil from the Permo-Triassic Phosphoria Formation, a thin marine limestone. This unit has moderate matrix permeability, but the significant structural deformation to which the reservoir units have been subjected has produced large-scale fracture connection. However, local smaller-scale fracture connections appear to be variable and often results in poor fracture permeability.

Several options are being considered for improving recovery from this reservoir that require better knowledge of the fracture system. These options include improved targeting of water injection for waterflooding, optimal horizontal drilling to better connect and link together lower recovery portions of the reservoir, and the selective reduction in water cycling through improved gel conformance treatment design and placement. As part of a DOE-funded study, the discrete fracture network (DFN) technique is being applied to optimize well placement and gel treatment in order to recover previously bypassed oil.

As the basis for the fracture study, four independent data sets were analyzed: outcrops at Wind River Canyon and Zeisman Dome, fracture and lithologic data from field wells, lineament maps from 3D seismic, and tracer tests. Individually, each data set confirms that fractures dominate the fluid flow in the reservoir rocks. Collectively, these data sets were used to construct a consistent, calibrated DFN reservoir model.

As part of a DOE-funded study, the discrete fracture network (DFN) technique is being applied to optimize well placement and gel treatment in order to recover previously bypassed oil. The current paper focus on a new approach to analysis of 3-D seismic data that allows the determination of the distribution of size and intensity of fractures controlling flow within the reservoir

Theory and Methods

One of the key input parameters for the DFN modeling technique is the distribution of fracture sizes. Traditionally two- and three-dimensional seismic data has imaged discontinuities on the scale of fault-blocks, while fractures controlling connectivity with reservoirs occur at length-scales below seismic resolution. Reservoir flow depends upon fractures at all scales, from the fault-block defining fractures to the meter-scale or less fractures. Recent advances in processing appear to determine parameters such as fracture orientation and intensity of these smaller fractures, but determining how many fractures there are in the reservoir at scales between meters and hundreds of meters has been an outstanding issue.

In order to combine data from different scales, it is necessary to determine whether the data sets are subsets of the same overall population of data, or whether the data set at one scale differs in terms of geological origins and properties with data from another scale. The evaluation of this question, and the determination of parameter values necessary for constructing a complete reservoir model, requires a combined geological and statistical approach. The formulation of a geological conceptual model of fracturing is critical to distinguishing fracture sets within each data set, and also for providing initial hypotheses as to how sets at different scales should be or not be related. Once these hypotheses have been proposed, they the hypothesized scaling relations are tested in a variety of ways.

This project has developed a new method for evaluating the scaling behavior of fracture sizes. The conventional method to test whether fractures at different scales may belong to the same parent population involves plotting the cumulative number of traces in each data set greater than or equal to a specific size as a function of the size. Since the areas for each data set may not be the same, the number is normalized by the data set area. Data sets are presumed to belong to the same parent population if the resulting plots approximate a power law. However, this type of approach can provide an incorrect answer if the spatial pattern of fractures is not completely random. For typical data sets, fractures tend to be clustered into networks or swarms, and as a result, the area renormalization is more complicated. This paper shows that the inclusion of a model of spatial intensity as a function of scale leads to a better match to a power law function, and also that the resulting parameters for the fracture model will predict a greater proportion of large fractures than a model that ignores the spatial clustering.

Examples (optional)

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References

Indicate whether an oral or a poster session is preferred