Paper Number 79105

Title **Integrated Fractured Reservoir Characterization: A Case Study in a North Africa Field**

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Journal SPE Reservoir Evaluation & Engineering
Issue Vol 5, Number 4, August
Pages 284-294

Summary

In fractured reservoirs, data directly related to fractures are scarce and 1D (e.g., core and image-log data). Other types of data are more widespread (e.g., seismic data) but generally are related only indirectly to fracture distribution. In such reservoirs, it is necessary to understand and then to model the fracture network on a fieldwide scale by integrating all available data.

We propose a methodology to achieve this objective. The methodology establishes relationships between the fracturing and other sources of data in a systematic workflow that goes from static 1D data to a 3D dynamic model. The methodology is described and illustrated with a case study from north Africa. In this field, fracture data from image logs and cores are related to (1) 3D seismic attributes (e.g., amplitude, coherency), (2) fault patterns, and (3) other types of well data (e.g., interval thickness, lithology index, and porosity). Production data also are used to quantify the contribution of each fracture set to flow, which then can be mapped on a reservoir basis with the more widely distributed log and seismic data. The resultant set of maps then is entered into a dynamic reservoir model. The methodology has been validated with a new well, the fracture network of which was accurately predicted in the reservoir by the model.

Introduction

Fractured reservoirs are by nature highly heterogeneous. In such reservoirs, fracture systems control permeability and can also control porosity. Fracture modeling is therefore a key development issue and requires an integrated approach from geology to reservoir simulation and well planning. Because fractures are below the limit of seismic resolution, the static models of fractures are constrained mainly by well data (e.g., cores or image logs) using conventional structural geology techniques.1 These models include the mechanical origin (shears vs. joints), the geometry (orientation, size, and frequency) and the typology (open vs. cemented) of the fracture network. The fracture permeability then can be assessed by relating the fracture aperture to the fracture excess conductivity measured on electrical image logs,2 critically stressed fractures within the present-day stress field,3,4 or both. It is the authors' opinion, however, that such approaches only give, at best, a relative estimate of permeability that must be calibrated against dynamic data. This requires the quantitative modeling of fracture flow behaviors. At the drainage-radius scale of wells, discrete fracture networks (DFNs)5,6 can be constructed and used to simulate flows and match them to well-test data.7 This allows us to derive the fracture input parameters for reservoir simulation.8 Far from wells, however, the lack of data makes DFN models very uncertain. The static modeling of the spatial distribution of fractures at the field scale and the use of these models as input to dynamic reservoir models are the purposes of this paper.

Methods have been presented to model field distributions of fractures based solely on the fracture density measured along wells.9 The scarcity of wells in which fracturing data are available makes such a direct mapping difficult and very uncertain, however. Geometrical methods based on the fractal theory predict subseismic fractures from seismic faults.10,11 These methods can be hazardous when used to extrapolate over several orders of magnitude (i.e., from seismic faults down to core scale fractures) and generally apply only to shear fractures, not to joint systems.12 Bourne et al.13 propose a geomechanical method to predict the fracture distribution related to the elastic stress field perturbation around faults. This technique does not allow the prediction of fractures that do not result from the activation of seismic faults (e.g., doming). Leroy and Sassi14 and Guiton15 suggest another geomechanical method that relies on an idealization of the real fractured rock by a continuum. They introduce opening and sliding displacements to represent the reservoir-scale deformation and the diffuse fracture patterns that accommodate it. This approach assumes a homogeneously fractured rock and therefore does not predict fracturing or faulting localization. Heffer et al.16 propose a geostatistical technique to interpolate strain/tensor components supposedly related to fracturing. The estimation is conditioned to well and structural data and is calibrated against well-test permeabilities. All these methods assume that the fracturing process is related to a limited number of geological parameters that constrain the mechanical behavior of fractured rocks. Although only one parameter may be needed to characterize a fractured reservoir,17-19 it is often the lack of a methodology to integrate the combined effects of structure, thickness, and lithology that leads geologists to focus only on the most important factor. With complex reservoirs, however, more comprehensive descriptions are unavoidable when producing reliable fracturing models. Ericsson et al.20 build an empirical and deterministic approach to derive a fracture density index that is a function of other indices related to reservoir variables like the structural curvature, the crestal distance, or the facies type. Similarly, Agarwal et al.21 relate the fracture intensity to both geological parameters and effective permeabilities to model field permeability distributions. Their approach is less empirical but remains fully deterministic (and hence inappropriate) to address the uncertainty inherent in the spatial distribution of fractures or permeabilities. Stochastic methods are the only way to account for such uncertainties. One approach22,23 consists of using a multivariate, nonlinear regression function of secondary (geological) parameters to fit well fracturing data (i.e., related to a fracture index). The stochastic aspect addresses the uncertainty on the regression model by random sampling of the data set. Repeatedly, a data subset is drawn and used to fit the regression function, which can be accepted or rejected according to some correlation criteria. If accepted, the multivariate regression function is applied to the whole field to produce a realization of the fracture index. The particularity of this approach is the use of a neural-network architecture to define the regression function. However, the approach generates unconditional realizations (fracturing data are partly honored) and does not allow the reproduction of any statistical model as inferred from the data.

In this paper, a geostatistical approach is presented to simulate fracture frequencies with the integration of primary fracturing data and any variety of secondary geological, geomechanical, or seismic information reflecting the understanding of the fracturing process. In the following, the method is presented and applied to a north Africa field. The results are validated against new drilling data, and their use as input to a reservoir model is discussed.