Petrophysical Rock Types, Pore System Parameters and Capillary Pressures Prediction in Multimodal and Heterogeneous Reservoirs

Samy Serageldin

Aramco

Abstract

Building a porosity, permeability and pore systems database in multimodal, heterogeneous reservoirs is a complex and time-consuming task. The database should be representative and statistically big enough to cover a universe of possibility. The present paper summarizes our workflow to build that database and how we use it with the help of our techniques and software to predict Petrophysical Rock Types (PRTs) and retrieve their related Capillary Pressures (PCs) and Pore System Parameters (PSPs).The database measured and retrieved from around 2000 core plugs. PRTs were defined based on Mercury Injection Capillary Pressure (MICP) measurements and Thomeer parameterization. The definition preserves the pore system modality and produces the right volume of micro, meso and macro-porosity. We used our in-house developed software to predict PRTs and their related PCs and PSPs in 1D and 3D space. The software operates using a modified K-nearest neighbor process with porosity, and permeability being the X and Y coordinates of the database map. It is a lookup technique, which looks at the most similar MICP measurements available in a reference database.With our representative database and invented technique, we succeeded to predict PRTs and their related PCs and we were able to model up to nine pore geometry parameters in 3D space. Because our software directly refers to real data, physically meaningful output of PSPs was guaranteed. The produced PCs are not averaged to a certain number of rock types; each cell in our 3D model has its own PC with up to nine Thomeer parameters. The techniques also allowed us to reproduce the reservoir heterogeneities needed in carbonate reservoirs, where not only water saturation but also flow behavior are strongly dependent on the complexity of the pore systems. The good PRTs and PCs prediction will increase saturation modeling accuracy and decrease uncertainty in the Original Oil In Place (OOIP) calculations.Our technique prevents the classic rock-type based capillary curve averaging method from smoothing out the reservoir property contrasts in 3D space. This is particularly important from a reservoir simulation perspective, since the rock property highs and lows, rather than its average, mostly controls flow behavior.