Conventional imaging not possible in oil-base mud

Jurassic and Cretaceous carbonates in the South region of Mexico are commonly tight but can be productive where porosity and permeability are locally enhanced by the presence of natural fractures or the formation of vuggy porosity as a product of diagenesis. To assess the possibility of completing the 8½-in section of a well, the operator wanted high-resolution formation images of the potential reservoirs. However, the well had been drilled with OBM to mitigate potential hazards, and conventional fullbore resistivity imaging tools are designed to operate in a conductive environment.

High-definition imaging versatility

With its increased signal-to-noise ratio, high-resolution analog-to-digital conversion, and novel signal processing technique, the FMI-HD high-definition microresistivity imager can acquire high-quality images in OBM borehole environments where the formation resistivity is sufficiently high and the oil/water ratio is low. The tool’s superior sensitivity to fine contrasts in formation resistivity increases image definition by a factor of four over that of conventional imaging for much greater visibility and hence interpretability of the borehole’s features.

Sufficient fracture density determined

The quality of the images acquired with the FMI-HD microimager is practically indistinguishable from images that would have been acquired in WBM. Bedding and fine laminations, fractures, and minor faults were identified. In addition, a core-like description and lithofacies classification were performed based on the image texture.

Data from the FMI-HD high-definition formation microimager is transmitted from the wellsite to the operator’s office in real time.
In wells drilled with OBM, fractures typically appear as high-resistivity (bright) features in microresistivity images. Without complementary data, an open fracture filled with resistive mud filtrate is essentially indistinguishable from a fracture that has been cemented by resistive minerals such as calcite or quartz. The losses that had occurred while drilling the interval were used to infer that the fractures are open. Other common sources of complementary information include acoustic images or advanced acoustic logs.

The interpretation of images from the FMI-HD high-definition microimager in the interval shown determined that fracture density was too low, which would make the reservoir zone unlikely to be productive. The operator then drilled a 6-in section with WBM, acquired another set of high-definition images with the FMI-HD microimager to determine fracture density, and successfully completed the well. Logging with the FMI-HD high-definition formation microimager is now a standard component of the operator’s formation evaluation program, with over 50 runs to date in the region.